From: Scott Tomashefsky

Subject: Re: Rule 21 Working Group: Next Steps

TO ALL PARTIES FOLLOWING THE ENERGY COMMISSION'S DG OII PROCEEDING (04-DISTGEN-1):

As a follow-up to last Wednesday's Rule 21 Working Group meeting, I want to bring everyone up to speed on schedules and progress related to the upcoming completion of the Rule 21 Working Group report that is due on November 10. First of all, I am attaching the drafts of the various sections that have been forwarded to me this morning. As I indicated at the 10/27 meeting, I will use these as a basis to develop the draft Rule 21 report and plan to have these documents docketed as a group in this proceeding. Much of the network interconnection write-up is contained in the attached meeting minutes, with further elaboration anticipated during the next couple of days.

The remainder of the schedule goes as follows:

1) I will prepare a draft of the Rule 21 report and circulate by close of business Friday (11/5).

2) Those of you who are interested in reviewing the document are welcome to join me in Sacramento on Monday 11/8 at 9:30 am in Conference Room 2 at the Energy Commission. This will give me an opportunity to incorporate any concerns/misrepresentations/omissions before the document is finalized the following day. Don't consider this a full Rule 21 working group meeting but please come if you want. Since the meeting will be held on the 2nd floor and you will need to go through security, please let me know if you are coming and we can expedite the sign-in process.

3) The final Rule 21 report goes to the docket and the Integrated Energy Policy Report Committee on or before close of business 11/10.

4) Public comments on the report are due 11/30.

5) The next Rule 21 working group meeting will be held on 12/2 at SDG&E's offices in San Diego. I will provide more specific details about which building and meeting rooms as we get closer to that meeting date. We can use some of that time to address the logistics of the 11/10 hearing.

6) The Energy Commission hearing to discuss the report and the public comments will be on 12/10, beginning here in Sacramento at 9:30 am.

7) The minutes of the last meeting are also attached.

Thank you for your continuing interest in this proceeding. Please do not hesitate to contact me if you have any questions.

Scott Tomashefsky
California Energy Commission
Advisor to Chairman Keese and Interconnection Project Manager
(916) 654-4896

Minutes for Rule 21 Working Group Meeting #61
October 27, 2004
Pacific Gas & Electric, Oakland, CA

There were 31 Working Group members in attendance in person or conferenced in by telephone. The next regular meeting of the Working Group is scheduled for December 2 at San Diego Gas and Electric's offices in San Diego.

Scott Tomashefsky, Chair

Aldridge	Pat	SCE	Mazur	Mike	3 Phases Energy
Blair	Tom	City of San Diego	McAuley	Art	PG&E
Blumer	Werner	CPUC/ED	Minnier	Randy	MPE Consulting
Brooks	Bill	Endecon Energy	Monson	William	MRW & Assoc.
Brown	David	SMUD	Ng	Steven	PG&E
Cook	Bill	SDG&E	Patrick	Robert	Valley Air Solutions
Couts	George	SCE	Prabhu	Edan	Reflective Energies
Duggan	Kevin	Capstone Turbine	Ross	Jim	CAC/EPUC
Goh	Jeff	PG&E	Savidge	Dylan	PG&E
Grebel	Ed	SCE	Sheriff	Nora	CAC/EPUC
Huang	Hann	ANL	Smith	Richard	SDG&E
Hyams	Michael	San Francisco PUC	Solt	Chuck	Lindh & Associates
Iammarino	Mike	SDG&E	Torribio	Gerome	SCE
Jackson	Jerry	PG&E	Tunnicliff	Dan	SCE
Luke	Robin	RealEnergy	Whitsel	Kim	PG&E

Process and Combined Group Notes

Rule 21 Advice Letter Progress and Status

SCE and SDG&E have pending advice letters that will more closely cite IEEE 1547 provisions throughout the Rule 21 tariffs. PG&E's filing is pending resolution of an ongoing protest by the City of San Diego regarding the ability of Rule 21 to export power. The next step in resolving the City of San Diego dispute is a phone call between Tom Blair, Mike Iammarino and Werner Blumer. The group anticipated that conversation to be held as early as October 28.

CRS Quarterly Data Reports (Per CPUC Resolution E-3831)

.As discussed in previous meetings, the group's desire is to eliminate the utilities' need to file a quarterly report on CRS activity per CPUC Resolution E-3831. While a report was filed earlier this month, the intent is officially eliminate the report filing by the next quarterly report date in January. Scott will attempt to resolve this with Valerie Beck of the CPUC's Energy Division before the next quarterly report is due.

PUC Data request
Valerie Beck has made a data request of all 3 utilities to try to determine what non-utility generation exists today. They have all responded. The WG indicated they would like to have access to those responses.

DG Activity Reports
The SDG&E report was distributed before the meeting. All 3 utilities indicated they would have current reports available at the December 2 meeting in San Diego.

DG OII (CEC-04-Dist-Gen) Action item review
Scott requested that all documents and comments on the 5 issues be in his hands by 9:00 Monday, November 1. He will distribute a draft on November 5 and will have a meeting in Sacramento on Nov. 8 to discuss the draft. The final report will be presented to the Integrated Energy Policy Report Committee by close of business on November 10. The report will also be docketed and distributed to the R.04-03-017 service list, the Rule 21 service list, and the Energy Commission's DIST-GEN list server.

Net Generation Metering
Nora Sheriff distributed Version 6 of the Net Generation Metering section on October 15. She then received comments and incorporated them into Version 7 which was distributed on October 26. PG&E provided a matrix which lists the various tariffs that may or may not require net generation metering, including tariff and data requirements and whether a meter is needed and/or required to be owned by the utility. Nora will be incorporating this information into Version 8 which will be sent to Scott by Monday morning, November 1.

Net Metering for Systems with "Combined" Technologies.
Gerry Torribio's document was distributed before the meeting and discussed. The Technical Group's comments have not yet been integrated. Bill Cook agreed to help Gerry incorporate this information into the document.

Several working group members questioned what fees and costs would apply to a Combined Technology system. If certain fees or system upgrade costs are borne by the utility in a net metering application and by the applicant in a non-eligible system, which fees apply if the project contains both a net metering and non-net metering elements?

Discussion continued on whether a Reverse Power Relay between the net metering eligible and non-net metering eligible generation and a meter at the point of common coupling would be sufficient to permit combined technologies. The utilities suggested this would not be acceptable under the current tariff structures because of the need to determine appropriate standby and other charges for the non-qualifying portion of the system.

Interconnection Fees/Costs
PG&E provided a revised version of the cost data matrix it provided at the October 13 meeting in Fontana. Several group members expressed concern that other utilities have not provided comparable costs and that PG&E's numbers may not be representative for all utilities.

Kim Whitsel of PG&E expressed concern that the pre-parallel inspection component continues to be a major cost element of the interconnection application. She stressed that the current fee structure does not provide an incentive to assure that repeat inspections are kept to a minimum. It should be noted that the actual cost of processing and completing an interconnection (short of incremental upgrade costs which are borne by the applicant) exceeding the application fee are absorbed in the utility's distribution cost component of rates. That being said, the group briefly discussed the distinction between how a distribution system improvement cost and an incremental system enhancement cost are classified. Scott reiterated that, regardless of the debate about the relationship between application fees and application costs, the fees were never intended to cover the costs.

Dispute Resolution Process
Scott stated that some working group members have problems with the current Rule 21 dispute resolution process and have suggesting changes. Others by contrast, specifically SCE, believe the process is working just fine. PG&E distributed a matrix comparing the Rule 21 dispute process with Massachusetts process. For purposes of the report, the group is attempting to incorporate specific experiences related to the process, including case studies from developers and utilities. To date, Real Energy has submitted its case study to the group. PG&E intends to provide some descriptive to the working group by November 1. Pat Aldridge of SCE will forward specific language on Rule 10 and potentially a graphic explaining the general complaint process presently used by the CPUC.

Interconnection Rules for Network Systems
This item is largely complete. The Technical Group will look at adding background information into the process outline including but not limited to the activities of the Massachusetts DG Collaborative and the Distributed Utility Integration Test (DUIT) program. The Technical Group will also develop timing for the process.

The Massachusetts Technology Collaborative met on October 20 to discuss the role of DG in distribution planning. Chuck Whitaker's initial comments were that they had similar issues and are undertaking a variety of areas where there it is beneficial to collaborating with them in the future. The Massachusetts Technology Collaborative meets monthly and will next meet on November 17. It is working on network systems and systems planning at this time.

Technical Breakout Group Notes

- **Review new addition to Line Section definition:**

The group reviewed the following Line Section definition addition:

Transformer and the Shared Secondary as a "Line Section"

A service transformer supplying multiple services in a shared secondary configuration system maybe considered a line section. This transformer and its connected secondary system is part of the Utility's Distribution System, and should be reviewed as line section for loading and voltage concerns.

This definition was reviewed and discussed. The question was raised as to whether a single-phase shared secondary should be considered a "line section" according to the above definition. Although it would currently fail many small ENET projects according to the 15% of line section screen, it was decided that utilities could use this definition internally, since ENET customers are not required to pay interconnection fees. Although voltage concerns are possible in a neighborhood with high penetration of ENET systems such as PV, usually those subdivisions are identified by the utility early in the process. The basic view of the group was to not prevent a shared secondary from being viewed as a Line Section, but that there is no need to specifically add language to the definition to force all utilities to consider a shared secondary a line section.

- **Establish process to address OIR task :**

Next the group reviewed the objectives and tasks developed by Chuck Whitaker and reviewed the paragraph introduction that was developed by Moh Vaziri and Jeff Goh. The introduction was rewritten in the following form and the Objectives and Tasked were discussed and revised to provide additional direction to Scott Tomashefsky to include in his report to the CPUC.

V. - Interconnection Rules for Secondary Network Systems

Introduction:

The rules for interconnecting generating facilities to secondary network systems are different compared with interconnections to radial systems. In the secondary network system, there are technical requirements resulting from the design and operational aspects of network protectors not employed on radial systems. In California, the major secondary network systems are located mainly in the metropolitan areas of San Francisco, Oakland, and Sacramento. Several distributed generation projects have been interconnected to various secondary network systems during the past few years. Due to lack of technical information and clear guidelines, there have been issues with some of these interconnections. By the current screening process in Rule 21, interconnections involving secondary networked systems are advanced to the "supplemental review" stage. Due to the nature of the protective schemes used in the networked systems, most of the interconnections now require a detailed study. Without interconnection guidelines, utility companies now have to study each project and establish their own interconnecting requirements on a case by case basis.

There has been an interest from the California Energy Commission's Integrated Energy Policy Report committee and other stakeholders to determine if any simple and uniform rules for interconnection of DG to networked systems may be added to Rule 21. Similar interconnection issues have also been identified in other parts of United States showing the need for guidelines. Some of the on-going efforts by other utilities and engineering groups addressing this issue are as follows:

- (a) Massachusetts DG Collaborative Technical Working group is conducting meetings on this issue.
- (b) California Energy Commission in collaboration with DOE has already approved a new testing program to study network interconnnections. Testing will conducted by the Distributed Utility Associates in California upon completion of the existing DUIT phase 1.
- .

Rule 21 technical working group had developed the following plan outline for this purpose.

Objectives:

- Define the issues (load, fault—Types: Spot, Area)
- Develop Supplemental Review information
- Determine general requirements (include in section D)
- Determine if opportunities exist for simplified interconnection (if so, include in section I)

Tasks:

1. Develop definitions, characteristics, and design philosophies for different types of networks to provide a common basis of understanding (DUIT report will be out for review and comments by the end of the month)
2. Identify network systems in CA
   - Locations
   - Physical characteristics
3. Identify the stakeholders nationwide who may be able to provide information
   - Utilities with network systems
   - DG suppliers
   - Customers on network systems who may be interested in DG
   - Regulators
   - Network equipment providers and other experts
4. Identify and Investigate other Projects and sources of documentation
   - DUIT proposed Network meeting and Network-related testing
   - Mass Tech Collaborative
   - PG&E white paper and other technical literature
   - IEEE 1547 (project proposed for a PAR (IEEE project authorization request))
   - Manufacturer data sheets/white papers
5. Identify and investigate the availability of other Rules and requirements
6. Identify and investigate existing DR on networks
7. Identify problems and solutions
   - Experience from utilities
   - Experience from system integrators
8. Investigate costs of protection schemes and protector rework

- **Export Screen Final Version for review:**

After months of debating the wording for the export screen question—which only served to add to the growing list of possible questions—an idea was put forward at the previous meeting to change the screen questions in Section I into titles. The group had been wasting an inordinate amount of time trying to hone screen questions, when the discussion should have focused on the content of the screen itself—this was generally viewed as a reasonable approach to refocus the discussion on the important issues.

Taking the guidance provided by Moh Vaziri in the Proposal 1, dated 9-21-04, the group decided to take the melded version of Moh's proposal that used a title for the export screen rather than a question. Also option 4 and option 5 were adjusted so that they have the same language. The question was raised as to the need to have a separate option 4 and 5 since ENET is a contractual issue, not an interconnection issue. The following proposed language is submitted for final review and approval at the December 2 meeting in San Diego:

Proposal - Changes to Screen 2:

Note: Option 3 and Option 4 have swapped numbers. Changes from 2004 Rule 21 in Turquoise.

I.3.b. Screen 2: Export Screen

Pass

- In order to pass this screen, the Generating Facility must either prevent export across the PCC by incorporating option 1, option 2, or option 3, or ensure export is limited to negligible levels by satisfying all of the conditions in option 4 or option 5

Fail

- All other Generating Facilities fail this screen.

Option 1: ("Reverse Power Protection"):
To ensure power is not exported across the PCC, a reverse power Protective Function may be provided. The default setting for this Protective Function, when used, shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay.

Option 2 ("Minimum Power Protection"):
To ensure at least a minimum amount power is imported across the PCC at all times (and therefore, that power is never exported), an under-power Protective Function may be provided. The default setting for this Protective Function, when used, shall be 5% (import) of the Generating Facility's total Gross Nameplate Rating, with maximum 2.0 second time delay.

Option 3 ("Relative Unit Size"):
This option, when used, requires the Net Nameplate Rating of the Generating Facility to be so small in comparison to its host facility's minimum load, that the use of additional Protective Functions is not required to ensure that power will not be exported across the PCC. This option requires the Generating Facility's Net Nameplate Rating to be no greater than 50% of the Producer's verifiable minimum Host Load over the past 12 months.

Option 4 ("Certified Non-Islanding Protection"):
To ensure that the export of power across the PCC is limited to acceptable, negligible levels, this option, when used, requires that all of the following conditions be met:

a) The Generating Facility must be Certified as Non-Islanding.
b) The total Gross Nameplate Rating of the Generating Facility must be no more than 25% of the nominal ampere rating of the Producer's service equipment;
c) The total Gross Nameplate Rating of the Generating Facility must be no more than 50% of the Producer's service transformer capacity rating. (This capacity requirement does not apply to Customers taking primary service without an intervening transformer);

d) The total Gross Nameplate Rating of the Generating Facility must be no more than
<we need to pick one of the following>
<10% of the Load Carrying Capability of the smallest primary conductor serving the Generating Facility>
--OR--
<the equivalent of 10 amps primary on EC's Distribution System (75kW at 4kV, 200kW at 12kV, or 360kW at 21kV)>

<u>Option 5 ("ENET or Expanded ENET")</u>:
To ensure that the export of power across the PCC is limited to acceptable, negligible levels, this option, when used, requires that all of the following conditions be met:

a) The Generating Facility must be Certified as Non-Islanding.
b) The total Gross Nameplate Rating of the Generating Facility must be no more than 25% of the nominal ampere rating of the Producer's service equipment.
c) The total Gross Nameplate Rating of the Generating Facility must be no more than 50% of the Producer's service transformer capacity rating. (This capacity requirement does not apply to Customers taking primary service without an intervening transformer).

d) The total Gross Nameplate Rating of the Generating Facility must be no more than
<we need to pick one of the following>
<10% of the Load Carrying Capability of the smallest primary conductor serving the Generating Facility>
--OR—
< the equivalent of 10 amps primary on EC's Distribution System (75kW at 4kV, 200kW at 12kV, or 360kW at 21kV)>
e) The facility must qualify for Net Energy Metering as defined by the CPUC.

The ampere rating of the Customer's Service Equipment to be used in this evaluation will be that rating for which the customer's utility service was originally sized or for which an upgrade has been approved. It is not the intent of this screen to allow increased export simply by increasing the size of the customer's service panel, without separate approval for the resize.

<u>Significance:</u>

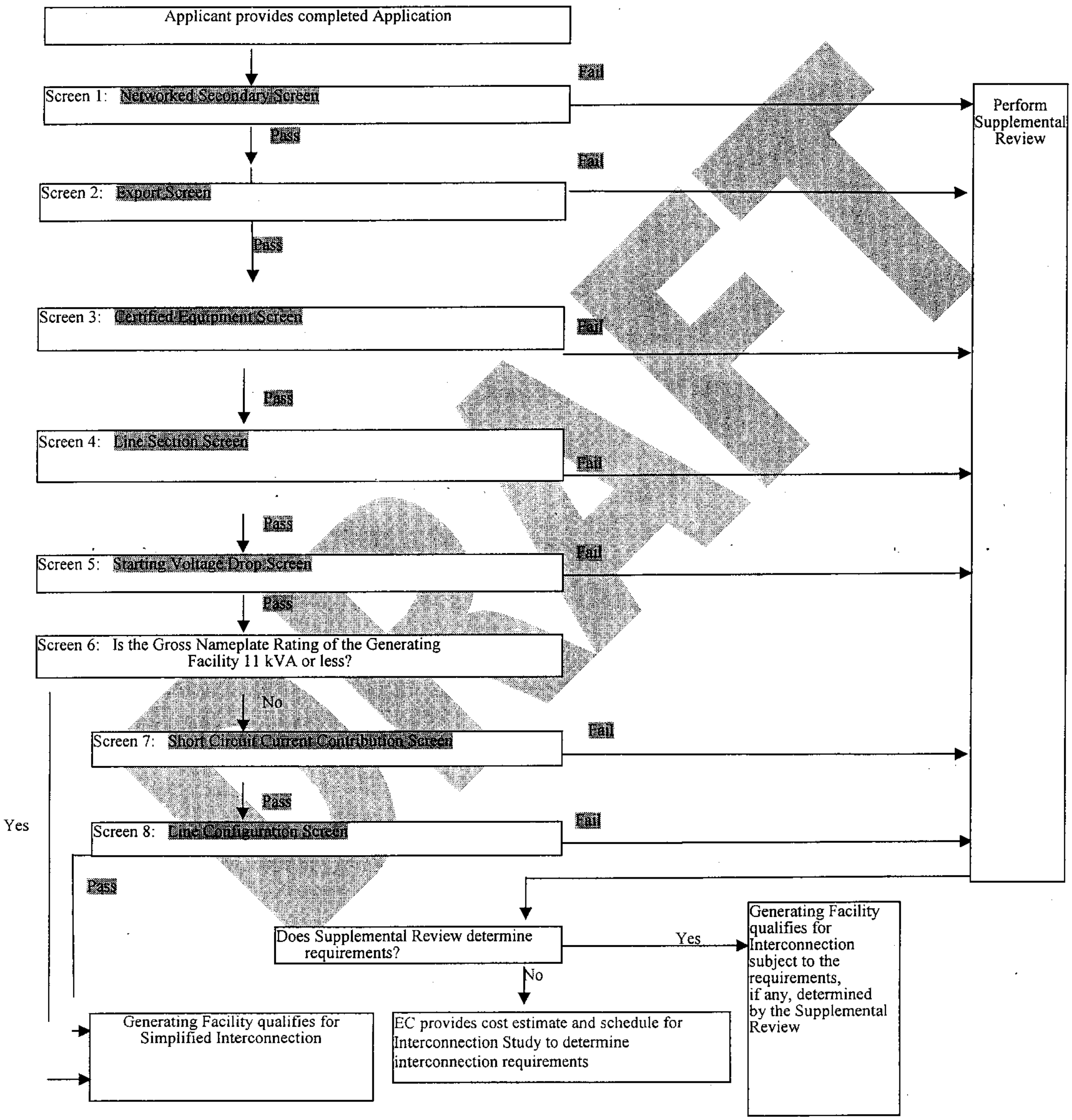
1. If it can be ensured that the Generating Facility will not export power, EC's Distribution System does not need to be studied for Load Carrying Capability or Generating Facility power flow effects on EC voltage regulators.

2. This screen permits the use of reverse-power or minimum-power relaying at the PCC as a positive Anti-Islanding Protective Function (Options 1, 2 and 3).

3. This screen allows, under certain defined conditions, for Generating Facilities that incorporate Certified Non-Islanding protection to qualify for Simplified Interconnection without implementing reverse power or minimum power Protective Functions (Option 4 and Option 5).

Proposal 2 - Changes to Review Process Flowchart:

Initial and Supplemental Review Process Flow Chart



To Do List:

- Final versions of issue documents and comments should be provided to Scott Tomashefsky by November 1, 9:00 AM. These include submissions by Nora Sheriff, Jerry Jackson, Gerry Torribio, Bill Cook and others.

Net-Generation Metering Issue

Rule 21 Workshop/DG-OIR Proceeding

Notes: *(1) Prepared for Rule 21 Workshop*
(2) for metering not at the Point-of-Common-Coupling (PCC)

Area	Tariff	Need For Metering	Data Required and Frequency	Meter Ownership	Notes
Generator gas tariff administration	G-EG/PU Code 218.5, QF Verification	In order to determine compliance with tariff requirement	Total kWh (Monthly)	Have allowed customer owned meters in the past	Calendar-month kWh data is gathered monthly ~~annually~~ in order to calculate monthly bills and calendar-year operating efficiency. Data is also used to validate that usage is less than 250,000 therms/year to establish permanent noncore status and, to meet operating efficiency requirements per PUC Section 218.5
	G-EG/Rule 9	In order to ensure timely and accurate monthly gas bills.	Total kWh (Monthly)	Utility	In order to assure timely gas bills, data must be obtained on specified dates (that align with the gas meter read date) within monthly billing cycles and in a format agreeable to the billing system. For new generators that have no PG&E-owned dedicated gas meter.
	G-EG	Ensure timely and accurate gas bills for mixed-usage customers, and ensure compliance with 218.5.	Total kWh (Monthly)	Utility (preferred)	Where there is mixed gas end-use at a customer's generating facility, net meter data is used to ensure the correct amount of gas is billed under G-EG
Standby Tariff Administration	Schedule S - Reservation Charge and Otherwise Applicable rate Schedule - demand charge	No metered data required, see Notes column	None	N/A	Standby demand charge waiver is provided under conditions of standby agreement (Form 79-280). Reservation Charge & Otherwise Applicable Rate Schedule demand charge
	Schedule S, Special Condition 7	Net generation profile is used to determine when customer is generating at above its load requirement.	Net generation profile metering	Utility	This is an option under Schedule S. Customer opts to be billed for "supplemental" and "back-up" service.
	Schedule S	To determine compliance with tariff provision - exemption from CTC charges	Total kWh (Monthly)	Utility (preferred)	Calendar-month kWh data is gathered annually in order to calculate calendar-year operating efficiency.

Non-bypassable charges (CTC, PPP, ND, TTA)	Preliminary Statement, BB	To determine compliance with tariff provision - exemption from CTC charges	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Preliminary Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requiremeent, metering output is the most accurate means of determing departed load. Other interconnection scenarios (e.g. over-the-fence {OTF}, or where there is no load history) make this method meaningless.

Area	Tariff	Need For Metering	Data Required and Frequency	Meter Ownership	Notes
Cost Responsibility Surcharges (CRS's)	E-DCG	To determine compliance with tariff provision - exemption from CTC charges, DWR Bond, DWR Power, and Regulatory Asset (RA). The RA will change to a Dedicated Rate Component (DRC) effective 2/1/05	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Prelim. Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requiremeent, metering output is the most accurate means of determing departed load. Other interconnection scenarios (e.g. OTF, or where there is no load history) make this method meaningless.
Self-Generation Incentive Program (SGIP)		Annual efficiency calculation requires calendar month kWh net gen production.	Total kWh (Monthly)	Utility	Where required per the Self-Generation Incentive Program; and all costs borne by the SGIP
Distribution System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the distribution system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local distribution system operator, for customer generating facilities greater than 1 MW; or generating facilities greater than 250 kW on less than 10 kV systems.
Transmission System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the transmission system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local switching center, for customer generating facilities greater than 1 MW.

DRAFT 4—10/30/04

RULE 21 WORKING GROUP

NET METERING FOR SYSTEMS WITH "COMBINED" TECHNOLOGIES

A. INTRODUCTION

1. This subject has been raised for discussion in meetings of the Rule 21 Working Group, and has been included in the August 17, 2004 scoping memorandum in the CEC's DG-OII (Docket No. 04-DIST-GENJ-1, 03-IEP-1). The scoping memorandum describes the problem as follows:

   > "The passage of California Assembly Bill 58 (Statutes of 2002) expanded the net metering program to include larger systems and technologies that are not just photovoltaic and wind. Fuel cells and biomass projects are now eligible for net metering consideration on a pilot basis. Customers who install generation that include generators eligible for net metering coupled with generators not eligible for net metering create challenges with respect to logging the costs of reviewing the interconnection application, metering requirements, and associated tariffs. The Committee understands that this issue is a growing concern among the utilities and would like further elaboration on the topic." (p. 3)

2. In response to the direction provided by the scoping memorandum, the Rule 21 Working Group has engaged in further discussions regarding logging of costs of reviewing applications, metering requirements and tariff administration associated with the integration of both Net Energy Metering (NEM) and non-NEM eligible generators. As those discussions have evolved, several additional, related, subject areas have been addressed:
   - The case in which two generators eligible for NEM under tariffs applicable to *different* generation technologies are combined (e.g. solar photovoltaic and dairy digester biogas);
   - The treatment of costs *other than* those associated with reviewing applications (i.e. metering or other utility added facilities, including infrastructure improvements);
   - Technical issues relating to the interconnection of combined technologies
   - Contractual issues relating to the interconnection of combined technologies

   Finally, it should be noted that, while the group has reached some conclusions with respect to this subject, it has also identified some fundamental issues of policy for which further guidance will be required. These are highlighted in the final section titled "Conclusions."

3. As the topics in this paper have been addressed in verbal discussion and in written comments by the membership of the Rule 21 Working Group, divergent opinions regarding certain issues have emerged. It is intended that these be identified in this document, as well as the parties taking the positions. Primary contributors to this document include Michael Iammarino (San Diego Gas & Electric), Gerry Torribio (Southern California Edison), Tom Blair (City of San Diego), Werner Blumer (California Public Utilities Commission, Energy Division), J. C. Solt (Lindh & Associates), and Edan Prabhu (Reflective Energies).

B. BACKGROUND

1. NEM is provided for under Public Utilities Code Section 2827 to customers with Photovoltaic, or Wind Energy, or a hybrid system of both. Since NEM was originally enacted for PV and wind, the Code has been modified to include dairy biogas and fuel cells.

2. The California Legislature stated its intentions with respect to NEM in the preamble to SB 656, which added Section 2827 to the Public Utilities Code in August 1995:

> "The Legislature finds and declares that a program to provide net energy metering for eligible customer-generators is one way to encourage private investment in renewable energy resources, stimulate in-state economic growth, *enhance the continued diversification of California's energy resource mix, and reduce utility interconnection and administrative costs*." [Section 2827. (a); emphasis added]

When the Legislature amended Section 2827 (a) in April 2001 by its passage of AB 29, it expanded its statement of intent to add the following goals: "[T]o reduce demand for electricity during peak consumption periods" [and] "help stabilize California's energy supply infrastructure...."

3. NEM customers that have a single PV technology based generator that is under 1 MW receive the following benefits under NEM: (1) departing load charges are not applied to the output of the generator including ND, PPP, CTC and FTA; (2) free interconnection review; (3) credit for any power produced in excess of load during a year at full retail rates [except for demand metered customers then the credit is exclusive of demand charge billings]; (4) waiver of standby fees; and (5) unconstrained two way flow of power through service entrance. Fuel cell and dairy biogas projects receive a credit for excess power based only on the generation component of their tariff. Dairy biogas customers also have the right to aggregate retail loads at other dairy operation related sites located on the same property to receive the benefit of the credit for excess generation.

4. Section 2827 does not address a customer who installs a qualified eligible NEM technology with other non-NEM eligible technologies, such as fossil fuel cogeneration. It also does not address how generators of two different technologies, each eligible for a different NEM tariff, are to be combined. As discussed in greater detail below, the CPUC addressed the issue of combining eligible NEM (solar or wind) generators with non-NEM eligible generators in 2003.

5. The issue of assuring proper tariff administration with a combined installation of NEM eligible and non-NEM eligible generators was addressed in principle by the CPUC in the first DG OIR (R.99-10-025).[1]
    a. The CPUC set forth the position that "integrated use of nonrenewable energy sources [does not exclude] eligible renewable generation connected to the same service account from net metering." The CPUC qualified this position by stating "the ineligible generator does not become eligible for net metering due to the combined configuration."[2]
    b. To ensure that non-NEM eligible generation did not receive the same treatment (and benefits) as NEM eligible generation, the CPUC suggested that Option 1 of Rule 21 (i.e. use of a reverse power relay to

[1] D.03-02-068

[2] Ibid, p. 61.

ensure that power is not fed back into the utility grid) could be used to "[provide] adequate assurance that a nonrenewable generation system, even when connected to the same service account as the eligible renewable generator, will not export electricity.[3]"

6. Subsequent to D.03-02-068, P.U. Code Section 2827 was further amended by legislation to expand the types of technologies eligible for net energy metering to include dairy digester biogas and fuel cells.[4]

C. DISCUSSION OF ISSUES

1. Recording and allocation of costs of reviewing the interconnection application and costs for utility metering or other added facilities, including improvements to infrastructure.

The Rule 21 Working Group has identified several scenarios under which an interconnection application might be submitted by a customer, based on the sequencing of installations:

a. The NEM-eligible generator was pre-existing and an application is made for a non-eligible generator;
b. The non-eligible generator is pre-existing and application is made for an NEM-eligible generator;
c. An application for eligible and non-eligible generators is submitted at the same time;
d. Application is made requesting the utility to approve export from the site when the non-eligible generator is in operation.

Each of the above scenarios will have unique ramifications with respect to the complexity of interconnection review, additional equipment and testing, and additional metering. As discussed further in Section F.3.b, policy guidance is required to clarify which party is responsible for the costs associated with interconnection review and facilities.

2. Metering and tariff requirements
   1. Combined technology generating facilities may impose special metering requirements beyond those which would apply to a single-technology NEM, to ensure that only energy from an NEM-eligible generator is metered for credit; proper credit factors applied where different NEM rates are applicable; ensure that non-NEM eligible generators are metered for tariff administration and distribution system monitoring; for biogas NEM, correct application of biogas generation credit against aggregated retail account.) It will also be necessary to assure that other tariffs associated with the combined technology generating facility can be properly administered (e.g. standby and departing load tariffs applicable to non-NEM eligible generation). As discussed in Section F.3.b, policy guidance is required.

[3] Ibid, p. 61.
[4] Sections 2827.9 and 2827.10, respectively.

3. Technical

a. While D.03-02-068 addressed objectives of encouraging use of NEM while maintaining proper administration of tariffs for NEM eligible and non- NEM eligible generation, it did not address technical aspects of coordinating protective devices for a combined installation. The Rule 21 Working Group has identified a number of issues relating to assuring adequate protection.

b. When a customer installs a generator, other than NEM eligible, such as a cogenerator, they must interconnect in accordance with Rule 21. The application of Rule 21 leads to three general options for a customer: (1) install relays that will trip the cogenerator off before power is exported on the grid (this is standard design), (2) install relays that will trip the cogenerator off before power is exported to the grid on more than a momentary basis, or (3) pay for and provide additional protective functions that permit safe operation in an export to the grid mode (typically requires the ability to detect faults on the utility distribution system- normally a more expensive design than the two former designs). Regarding Options (1) and (2) above, it is essential for safety to utility's electrical workers and distribution system that the customer's non-NEM generator breaker trips open if export is detected for a period longer than the prescribed setting. This prevents the formation of an unintended island under a utility outage condition. Absent the presence of a machine-based generator, the certified anti-islanding inverters used in NEM systems will shut down during a utility outage. However, when a machine-based generator is operating in parallel, these NEM systems may not detect the utility outage and cease production since they do not have the ability to differentiate between power supplied from the utility and power supplied from the cogenerator. This is a safety issue that must be addressed whenever a customer installs a photovoltaic system in combination with other cogeneration technologies. Potential solutions to some of these issues are discussed further in Section E.

6. Contractual

a. Existing CPUC-approved interconnection agreements for distributed generation and NEM do not address combined technology generating facilities:

b. Principles to be embodied in an interconnection agreement for combined technology NEM:

(a) Non-export (or inadvertent export) limits on non-eligible generators should be maintained;
(b) Insurance provision for Generating Facilities with non-eligible generators should be included;
(c) Phased installation of eligible and non-eligible generators should be addressed;
(d) Review and facilities costs for non-eligible generation should be addressed.
(e) Departing load and standby charges applicable to non-eligible generators should be addressed.

c. The Rule 21 Working Group has facilitated the development of uniform contracts for several types of non-NEM eligible distributed generation generating facility; it is anticipated that it would be a useful forum to assist in the development of suitable agreements for combined technology NEM generating facilities.

D. POTENTIAL SOLUTIONS TO METERING AND NEM TARIFF ADMINISTRATION ISSUES

1. NEM eligible and non-eligible generator: No export while non-eligible generator is operating (suggested by CPUC in D.03-02-068, using reverse power relay[5] per Rule 21 Option 1)
   a. Discussion: Under this approach endorsed by the CPUC, if the combined total generation of both NEM eligible and non-NEM eligible generators exceeded total on-site electrical load, the non-NEM eligible generator would trip. Any export power metered at the Point of Common Coupling would, therefore, represent only NEM eligible generation.
   b. Pros: Consistent with CPUC guidance. Simple. One or more combined technology projects have been interconnected on this basis already.
   c. Cons: In order to avoid nuisance trips of the non-eligible generator, the customer can adjust its regulation to ensure that its output remains below trip point. However, depending on the specifics of the installation, such operation of the non-eligible generator below its full rating could result in less than optimal efficiency. Also, this approach does not address the case of multiple generators eligible for different NEM tariffs, in which case all exports would be "eligible"—just treated differently for credits and retail load aggregation if dairy biogas (see section 3 below).

2. NEM eligible and non-eligible generator: Allow export while non-eligible generator is operating, up to the limit of the output of the eligible generator (proposed by City of San Diego)
   a. Discussion: Allow export of energy and tariff credit up to the limit of the eligible generation (Solar, Wind) when the eligible generator is operating. Non-eligible generator operates with trip or governor control to load follow and prevent export above eligible generator value.
   b. Pros: Allows maximum size distributed generation for a given site. Most cost effective for customer generator.
   c. Cons:
   Possible extra meter cost and complex generator controls. Export limit should be the actual recorded energy produced by the eligible generator, rather than a fixed limit equal to its nameplate capacity.
   Stacking of resources: Would it make this an export project rather than net energy metering?
      <u>Utility Position</u>: Proposed preferential "stacking" of eligible generation on top of non-eligible generation under this approach makes it a renewable energy *export* generating facility rather than a *net energy metered* generating facility. It would not necessarily "reduce demand for electricity during peak consumption periods" as encouraged by P.U. Code Section 2728 (a), especially since export is anticipated to occur during times other than utility peak load periods (i.e. weekends).
      <u>San Diego Position</u>: Using the current NEM tariff a system may be sized at twice the actual load and the net production over a twelve month period will zero the customer usage from the grid. Any excess output over the *annual* usage creates no credit for the customer-generator. The stacking order should allow the

[5] In many Rule 21 installations, an <u>under-power</u> relay (Option 2) has proven to be a more practicable solution to the non-export requirement than the reverse power relay. This solution should work equally well with an under-power relay.

eligible output to create credits against other usage up to the output of the eligible generator.

Stacking of resources: Would this arrangement enhance energy diversity?

Utility Position: Maximum allowable capacity distributed generation for a given site can *already* be accommodated within the inadvertent export limitation for non-eligible generators. Stacking eligible generation on top of non-eligible generators to allow the customer to maximize their NEM credit would not further the intent of Section 2728 to "enhance the continued diversification of California's energy resource mix" since non-eligible generators are typically natural gas-fired.

San Diego Position: The export of energy during midday does support energy diversity and during the weekday periods all generation is used at the site with additional power used from the grid.

Stacking of resources: Would this encourage uneconomic dispatch?

Utility Position: Allowing resource stacking proposed in this approach appears to encourage an uneconomic dispatch of generation resources from a societal standpoint by some customers (instead of using solar or wind to serve on-site load first—at zero fuel cost—the customer would be encouraged to serve as much load as possible with fossil fired generation first, to "save" renewable generation for export to maximize NEM credit. Moreover, current regulations governing interconnection of customer generation do not impose any conditions on thermal efficiency—i.e., the non-eligible generator could be non-cogeneration. The uneconomic dispatch inherent in this stacking approach also results in greater cost shifting to other utility customers because the effective cost of the "renewable" export energy (i.e. the full bundled utility retail rate) is typically higher than the cost at which utilities can procure renewable resources through a competitive solicitation process.

San Diego Position: A typical installation will include a cogeneration system which would be designed for the most efficient heat rate for the particular installation. To meet the current requirements [for exemption from standby and non-bypassable tariff charges] the efficiency would be designed at 60 percent or better. This is not uneconomic when compared to distant baseload plants with transmission losses considered.

3. Two or more NEM-eligible generators: Export allowed
   a. Discussion: For two generators, each eligible for a different NEM tariff, the task would be to distinguish between the exports from each to allow proper application of the differing credits and retail load aggregation (if applicable). This could be accomplished by metering each generator to determine its production.
   b. Pros: Allow administration of different rates.
   c. Cons: Possible extra meter cost; Tariff issue: can a customer take service simultaneously under two NEM tariffs? Or must they choose one? Not a sufficient solution if non-eligible NEM generation is also installed.

E. POTENTIAL SOLUTIONS TO TECHNICAL ISSUES

1. It is technically feasible to provide adequate protection and metering for all variations of eligible and non-eligible generators. Rule 21 as it exists allows for

evaluation of all interconnections of multiple tariffs. Each application to interconnect would be required to state what the existing condition is (e.g., NEM-eligible system already installed), and what the proposed change is (e.g., a non-eligible system to be installed). The utility review will evaluate the impact of the proposed change and prescribe the requirements for the change. Evaluation of multiple tariffs will often require a full interconnection study.

2. While the process of technical review and approval of combined technology generating facilities is site specific, and also would be affected by the sequencing of installation as discussed in Section C above, the Rule 21 Working Group has developed some preliminary concepts for approaching such a review:

a. Case 1--Two or more generators, with only one eligible:

(1) If exporting when the non-eligible is running:

(a) Metering of the eligible generator

(b) Additional protection to accommodate the export (as required)

(c) Additional control to limit export from non-eligible generator (see Sections D and F.3.a) Protection for export while the non-eligible generator is running will usually be more expensive. The customer should have the option to choose whether or not to export when the non-eligible generator is running.

(2) If non-exporting, or capable of export only when the non-eligible is not running:

(a) Standard Rule 21 requirements. For example, if all interconnection systems are inverter based and certified, the system will probably qualify for simplified interconnection.

b. Case 2--Two or more generators, with at least two types of eligible generator:

(1) If exporting:

(a) Metering of each eligible generator if the two NEM tariffs are different (e.g. one PV and one fuel cell).

(b) Additional protection to accommodate the export (as required)

(c) Additional control to limit export from non-eligible generator (see Sections D and F.3.a) .

(2) If non-exporting, or capable of export only when the non-eligible is not running:

(a) Metering of each type of eligible generator.

F. CONCLUSIONS

1. The concept of interconnecting multiple technology/tariff generators on the customer's side of the meter, whether for a generalized distributed generation generating facility or a generating facility using generators which would be eligible for interconnection under NEM tariffs does not present any insurmountable obstacles from a technical standpoint (i.e. operation and protection of the utility distribution system).

2. For cases involving only eligible generators (both of which would be allowed to export under their respective NEM tariffs), a metering solution as discussed in Section D.3 above may be workable provided tariff administration issues can be worked out.

3. Policy issues remain to be resolved with respect to how the fundamental intent of the NEM program as established by the California Legislature should appropriately be carried out with respect to peak reduction, self-consumption, overall societal cost and economic dispatch. It is recognized that these are properly addressed in the CPUC's DG-OIR and other venues. In the context of the Rule 21 Working Group's review of the interconnection of a combined technology generating facility to the grid, policy guidance is required on the appropriate limits to be placed on exports from such a facility. Also, issues remain in the areas of tariff administration, equitable allocation of study costs, interconnection costs and tariff charges . This policy issue is summarized as follows:

   a. Is the CPUC-recommended methodology for interconnecting and metering an NEM-eligible generator and a non-eligible generator, as set forth in D.03-02-068, an appropriate basis on which to interconnect such generating facilities?
   Utility Position: Taking into account the various factors discussed above, not the least of which is the specific guidance provided by the Legislature regarding its intent when it passed the NEM legislation, the interconnection methodology endorsed by the CPUC in D.03-02- stands out as the best approach proposed thus far to interconnect the combination of an eligible and non-eligible generator, while balancing the interests of both the individual utility customer who installs the generators and other customers in general.
   San Diego: As stated in Section D.2 above, any methodology which prevents export from the NEM-eligible generator while the non-eligible generator is operating is inappropriate as it reduces the economic benefit which the customer might otherwise enjoy under the NEM tariff, and reduces the efficiency at which the non-eligible generator operates.

   b. Should customers who install combined NEM-eligible and non-eligible generating facilities be subject to interconnection review fees or study costs, costs for interconnection facilities or utility distribution system upgrades, and tariff charges (standby and departing load) which would otherwise be applicable to the non-eligible generator, in the absence of the NEM-eligible generator?

   The prospect of combining NEM-eligible and non-eligible generators in a single interconnection raises the issue of how to address the fact that NEM tariffs largely exempt customer from interconnection application fees, charges for interconnection studies and interconnection facilities, while non-eligible generators are not exempt from such charges. Setting aside the question of whether the application fee structure currently provided in Rule 21 is reflective of actual costs incurred by utilities in performing the interconnection reviews, it can nevertheless be stated that the review work required to interconnect the non-eligible generator in a combined technology project must still be done, regardless of the presence of an accompanying NEM-eligible generator.

Utility Position: It is appropriate for utilities to collect application fees and other charges appropriate to the non-eligible generator(s) installed in combination with eligible generators in the normal manner set forth in Rule 21 and other tariffs.

San Diego Position: The Legislature created laws that value distributed generation and renewable generation as general benefit to the citizens. Legislation that supports distributed generation is being made uneconomic to many customers because of the incremental cost for interconnection issues and various tariff charges. The costs for infrastructure improvements needed (as determined by the local utility) to interconnect with the grid should be the responsibility of the utility with the cost recovered through rates.

Recommendations and Individual Member Positions of the Rule 21 Working Group on Phase 1 Issues

California Energy Commission
November 10, 2004

DISCLAIMER

This paper, on certain Phase I issues, represents a consensus opinion of the Rule 21 Working Group. For other Phase I issues where consensus has not been reached, ~~it lays out~~ the different positions of individual Rule 21 Working Group members are identified. This paper generally reflects the experience of many members who work within the distributed generation (DG) community on a regular basis.

INTRODUCTION

As general background, the Rule 21 Working Group includes representatives from all aspects of the DG community, with utility personnel, DG manufacturers, project developers, DG customers, and regulators each represented in some form. Approximately 35 members actively participate in regular meetings, held every 4-6 weeks. Another 200 members track developments via an e-mail distribution list. Updated materials related to the Working Group, including meeting minutes, Rule 21 equipment certification information, as well as technical documents are available on the California Energy Commission website at www.energy.ca.gov/distgen.

The California Energy Commission (Commission) oversees the Working Group. Contract technical support is funded by the Commission's Public Interest Energy Research (PIER) program. To date, approximately $830,000 [to be updated by Scott Tomashefsky] of public funding has been used to support the Rule 21 effort.

The initial focus was to craft a model Rule for the interconnection of distributed generation facilities installed and operated by utility customers; this was generally accomplished during calendar year 2000. The group now meets for the sole purpose of improving the interconnection process. Issues are debated and addressed in varying degrees. Resolution of issues is often reached. In some instances, however, additional policy direction from policy-makers is required.

These recommendations and positions are presented to the Commission pursuant to its and the California Public Utilities Commission's (CPUC) Scoping Memoranda in Docket 04-DIST-GEN-1, and Rulemaking 04-03-017, respectively.

INTERCONNECTION ISSUES FOR DETERMINATION IN PHASE 1

Five interconnection issue areas are to be examined in Phase I of this docket: metering issues; the dispute resolution process; interconnection fees; metering for systems with combined technologies[1]; and interconnection rules for network systems.

I. Metering Issues

The Commission requested input on metering questions that focused on whether customers should bear financial responsibility for the meter and whether the utility should require customers to use a utility-supplied billing-grade meter on the customers' generation units. Specifically, the Commission posed the following questions:

1) Should each new customer be financially responsible for the installation, operation, and maintenance of utility-supplied billing-grade metering on all new customer generation units?

2) Should the utility require a customer to utilize a utility-supplied meter on its generation units?

The Rule 21 Working Group members hereby submit their respective positions on metering issues to address the Commission's request for input. These metering issues have been framed by the Working Group as follows:

1) whether net generation metering should be required for all new non-net energy metered interconnections~~in all circumstances~~;

2) if net generation metering is required, what grade of meters should be required; and

3) if ~~net generation~~ metering is required, whether non-utility or third-party meters may be used.~~; and~~

~~4)future metering questions [thermal metering requirements?].~~

Briefly, the utilities state that net generation metering should be required for all new non-net energy metered DG interconnections~~ing projects~~, that the meters must be revenue quality and ~~that they prefer~~ that the meters be utility-owned meters. On the other hand, certain utility ratepayers, DG manufacturers, project developers, and DG customers support a different approach to the installation of net generation metering whereby imposition of such metering is selectively required. These DG related parties state that

[1] Combined technologies refers to ~~[Define "combined technologies" (i.e.,~~ a combination of technologies at one site, such as eligible ~~and non-eligible~~ net energy metering technologies and non-eligible net energy metering technologies located at the same site, for example, a 20 kW photovoltaic (solar) electrical generating system [an eligible technology] on the same site as a 50 kW diesel generator [a non-eligible technology]..~~)]~~

net generation metering should be required in those circumstances where the customer receives publicly-funded incentives or standby exemptions, but that under other circumstances where less intrusive methods or more cost effective means for the DG customer or both of providing data are available, net generation metering is unwarranted. Additionally, ~~-~~ some members of the DG community question the need for billing-grade meters and for ~~-~~ utility ownership of the meters. All parties, including the utilities, see this phase and its companion CPUC proceeding R.04-03-017 as the ~~time and place~~possible venue ~~to~~ for establishing any necessary protocols for third-party provision of net generation metering services.

The bases for the different positions, as presented by the respective parties in the Rule 21 Working Group, are set forth below to provide Committee Members and Commission Staff, in conjunction with the public comments to be filed on these issues, a starting point for reasoned policy decisions. The policy decisions to be made are ~~[here is what we'd like the Commission to decide:~~

- First, should net generation metering be a blanket interconnection requirement, *i.e.*, mandated in all circumstances, or should it only be required in some circumstances? ~~If yes, go here; if no, go there.~~
- Second, where net generation metering is ~~if~~ required, should the net generation meter be revenue quality, *i.e.*, what will the data collected by the meter ~~to be~~ used for and what quality of data is needed, or would some lesser quality of meter suffice? ~~(that is—)~~
- Third, where net generation metering is ~~if~~ required, may non-utility parties own the meter, or must the meter be owned by the utility, *i.e.*, which party should pay for the meter?

The threshold question is whether net generation metering should always be required for all non-net energy metered interconnections.

A. Should Net Generation Metering Be Required In ~~All Circumstances~~For All New Non-Net Energy Metered Interconnections?

This section first describes the current Rule 21 language on net generation metering; ~~second~~next, it sets forth relevant statutory and incentive program requirements, followed by ~~regulatory agency~~CPUC decisions and utility tariffs; ~~third~~then, the utility rationales for their positions are provided; and ~~fourth and~~ finally, positions held by most other non-utility Working Group members are explained. This format is followed in each of the ensuing sections on metering. Please note that this section I.A. does not address the questions of meter quality (addressed in I.B.) or meter ownership (addressed in I.C.).

The threshold issue is whether or not net generation metering should be mandatory for all non-net energy metered customer generation in all circumstances. Net generation metering is defined in Rule 21 as:

Metering of the net electrical power of energy output in kW or energy in kWh, respectively, from a given Generating Facility. This may also be the measurement of the difference between the total electrical energy produced by a Generator and the electrical energy consumed by the auxiliary equipment necessary to operate the Generator. For a Generator with no Host Load and/or Public Utilities Code Section 218 Load (Section 218 Load), Metering that is located at the Point of Common Coupling. For a Generator with Host Load and/or Section 218 Load, Metering that is located at the Generator but after the point of auxiliary load(s) and prior to serving Host Load and/or Section 218 Load.

Rule 21, Section H. Notably, all parties agree that if net generation metering is to be required for all new non-net energy metered customer generation, that requirement will be implemented based on the CPUC's Final Decision. As stated in the White Paper submitted by the Working Group to the Commission and CPUC on June 5, 2003, "*The utilities agree that their metering requirements are implemented on a prospective basis and that customers already connected will not be subject to changed metering configurations.*"[2]

1. Current Rule 21 Net Generation Metering Provision

Section F of Rule 21 addresses Metering, Monitoring and Telemetry requirements. In relevant part, it currently states:

For purposes of monitoring Generating Facility operation for determination of standby charges and applicable non-bypassable charges as defined in [Investor Owned Utility's (IOU)] tariff, and for Distribution System planning and operations, consistent with Section B.4 of this Rule, [IOU] shall have the right to specify the type, and require the installation of Net Generation Metering equipment. [IOU] shall only require the Net Generation Metering to the extent that less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available. In exercising its discretion to require Net Generation Metering, [IOU] shall consider all relevant factors, including but not limited to:

a. *Data requirements in proportion to need for information;*
b. *Producer's election to install equipment that adequately addresses [IOU's] operational requirements;*

[2] Rule 21 Working Group White Paper, at 5. Working Group members recognize that the Commission and CPUC might consider implementation of the final net generation metering decision on a ~~restrospective~~retrospective basis as well as on a prospective basis, that is, if net generation metering is not required in some circumstances, such metering could be removed at the customer's option and alternatively, if net generation metering is required in all circumstances, such metering could be ordered to be installed on generators already interconnected. Some utility ratepayers with customer generation, many of whom have operated for decades without such metering, have indicated that they would strongly oppose any attempt to retroactively impose net generation metering on existing, interconnected customers with on-site generation.

c. *Accuracy and type of required Metering consistent with purposes of collecting data;*

d. *Cost of Metering relative to the need for and accuracy of the data;*

e. *The Generating Facility's size relative to the cost of the Metering/monitoring;*

f. *Other means of obtaining the data (e.g., Generating Facility logs, proxy data, etc.); and*

g. *Requirements under any Interconnection Agreement with the Producer.*

[IOU] will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Net Generation Metering equipment in each instance along with the size and location of the facility.

Rule 21, Section F.3. Rule 21 provides that this sub-section, along with subsection F.5 on telemetry requirements, will sunset on December 31, 2004. *See* Rule 21, Section F.6.

The following section describes the requirements for net generation metering in the California Public Utilities (PU) Code and the Self Generation Incentives Program (SGIP) Handbook.

2. Circumstances Under Which Net Generation Metering Is ~~Clearly Required By Law~~Required By Law Or For Participation In Incentive Programs.

Net Generation Metering is explicitly required by the PU Code ~~under three circumstances: (1)~~ to evaluate the efficiency of Distributed Energy Resources (DER)[3] granted standby charge exemptions. The SGIP Handbook also requires net generation metering~~; and (2)~~ to gather data on the ~~Self Generation Incentive Program (~~SGIP~~)~~ participating generators. ~~; and (3) some net energy metering projects.~~

a. The Evaluation of the Efficiency, Emissions and Reliability of DER Required by the PU Code ~~Standby Exemptions Require~~Necessitates Net Generation Metering.

The PU Code mandates an evaluation the efficiency, emissions levels and reliability of DER. ~~[Explanatory sentence.]~~ To perform this evaluation, the PU Code requires the

3 DER, a subset of DG, are statutorily defined as *"any electric generation technology that meets the following criteria: (a) commences initial operation between May 1, 2002 and June 1, 2003, except that gas-fired DER that are not operated in a combined heat and power application must commence operation no later than September 1, 2002. (b) is located within a single facility. (c) is 5 megawatts or smaller in aggregate capacity. (d) serves onsite loads or over-the-fence transactions allowed under Sections 216 and 218. (e) is powered by any fuel other than diesel. (f) complies with emissions standards and guidance adopted by the State Air Resources Board ... "* PU Code Section 353.1

DER customer to annually provide such information, recorded on a monthly basis, to the CPUC. PU Code Section 353.15 provides:

> *(a) In order to evaluate the efficiency, emissions, and reliability of distributed energy resources with a capacity greater than 10 kilowatts, customers that install those resources pursuant to this article shall report to the commission, on an annual basis, all of the following information, as recorded on a monthly basis:*
>
> *(1) Heat rate for the resource.*
> *(2) Total kilowatthours produced in the peak and off-peak periods, as determined by the ISO.~~;~~*
> *(3) Emissions data for the resource, as required by the State Air Resources Board or the appropriate air quality management district or air pollution control district.*
>
> *(b) The commission shall release the information submitted pursuant to subdivision (a) in a manner that does not identify the individual user of the distributed energy resource.*
>
> *(c) The commission, in consultation with the State Air Resources Board, air quality management districts, air pollution control districts, and the State Energy Resources Conservation and Development Commission, shall evaluate the information submitted pursuant to subdivision (a) and, within two years of the effective date of the act adding this article, prepare and submit to the Governor and the Legislature a report recommending any changes to this article it determines necessary based upon that information.*

The DER data required by PU Code 353.15 cannot be gathered without net generation metering. The precision of the above data may not require revenue-quality metering. Further, it is uncertain whether the meter would need to be utility owned. These issues of meter quality and meter ownership are addressed more fully below in Sections I.B. and I.C.

b. ~~CPUC's~~ Net Generation Metering Is Required by the SGIP Handbook For Participation In The Self-~~-~~Generation Incentive Program (SGIP).

All SGIP participating generating systems are required by the SGIP Handbook to have electric net generation metering. The following excerpt is from the SGIP Handbook, dated January 17, 2004, Rev 4, 5.2.1, and describes the required metering:

> *Every system installed under the program shall be equipped with a dedicated, recording, time-of-use or interval meter to measure and record electrical generation output (i.e. Net Generation Output Meter). Many installations will require this type of electrical metering as a condition of interconnection with the*

utility grid. In the case of investor owned electric utilities, this means compliance with their filed CPUC Rule 21, Generating Facility Interconnections. Specifications for the net generator output meter can be found on the Program Administrator or the electric utility website.

Additional metering is required for fossil fuel-fired generation participating in the SGIP. Fossil fuel –fired generators are to have supplementary metering to record waste heat utilization, and fossil and renewable fuel generators are to have metering to measure renewable fuel consumption. The following excerpt is from the SGIP Handbook, dated January 17, 2004, Rev 4, 5.3 Other Energy Metering Requirements:

> *The CPUC requires that Level 2 and 3 installations be evaluated for compliance with program requirements for efficiency and waste heat recovery, and use of renewable/non-renewable fuels.* ***As a condition of receiving incentive payments in the program, Applicants agree to allow the Program Administrator, or the Administrator's independent third-party consultant, to conduct measurement and evaluation activities on a completed installation.*** *All labor and material costs for instrumentation and data collection required for the program evaluation will be borne by the Program Administrator. Results of measurement and evaluation activities will have no bearing on the incentive payment received, with the exception of some projects utilizing renewable fuels (Level 1 fuel cells and Level 3-R).*

Based on the SGIP Reservation Request Form, Rev. 4, dated January 17, 2004, The use of the data from these meters is limited to program evaluation, measurement and verification (EM&V):

> *E. Host Customer understands that the Program requires inspections and measurements of the performance of the proposed generating system. Host Customer shall permit Program Administrator, its employees, contractors, and agents, during normal business hours, to: (a) install all necessary performance measurement equipment on the System in order to enable Program Administrator to accomplish performance evaluations; and (b) demonstrate, inspect, monitor, and photograph the System. These data and field measurement documentation are not for purposes of enforcement and shall not be released to outside parties, except as may be required by the California Public Utilities Commission (CPUC).*

These requirements, applicable to all customers participating in the SGIP, clearly require Net Generation Metering. Again, however, the type and ownership of the meter remain in question and will be examined in more detail in sections I.B. and I.C, respectively ~~below~~.

c. Special Gas Rates

Cogeneration gets special gas rate consideration because of PU Code Section 218.5, and therefore a net generation meter is necessary for the correct application of the gas rate.

~~c. Net Energy Metering~~

~~[Explanatory Sentence]~~

> ~~**PU Code Section 2827.8.** *Notwithstanding any other provisions of this article, the following provisions apply to an eligible customer-generator utilizing wind energy co-metering with a capacity of more than 50 kilowatts, but not exceeding one megawatt, unless approved by the electric service provider.*~~
>
> ~~*(a) The eligible customer-generator shall be required to utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions. All meters shall provide "time-of-use" measurements of electricity flow, and the customer shall take service on a time-of-use rate schedule. If the existing meter of the eligible customer-generator is not a time-of-use meter or is not capable of measuring total flow of energy in both directions, the eligible customer-generator is responsible for all expenses involved in purchasing and installing a meter that is both time-of-use and able to measure total electricity flow in both directions. This subdivision shall not restrict the ability of an eligible customer-generator to utilize any economic incentives provided by a government agency or the electric service provider to reduce its costs for purchasing and installing a time-of-use meter.*~~
>
> ~~PU Code Section 2827.9 Experimental Biogas NEM and PU Code Section 2827.10 Experimental Fuel Cell NEM~~

The following section lists situations in which Net Generation Metering has been expressly precluded or judged unnecessary.

32. Circumstances Under Which Net Generation Metering Is ~~Explicitly~~ Precluded ~~Forbidden~~ or Deemed Not Required By Law And Utility Tariffs.

The CPUC decision on the question of Net Generation Metering and current utility tariffs may inform the policy determination on whether Net Generation Metering should be a blanket requirement for all new non-net energy metered interconnections.

~~The FERC Order and CPUC decision on the question of Net Generation Metering may inform the Commission's policy determination on the question of whether Net Generation Metering should be a blanket requirement in all circumstances.~~

~~a.FERC Finds CAISO Net Generation Metering Unjust and Unreasonable.~~

~~The Federal Energy Regulatory Commission (FERC) has addressed the question of whether customer generation, particularly Qualifying Facilities (QFs), in California must submit to a California Independent System Operator (CAISO) requirement of net generation metering. Although different terms are used, *e.g.*, gross meter for net generation output meter, the CAISO gross metering proposal was equivalent to the Net Generation Metering defined in Rule 21. FERC ordered the CAISO to meter QFs only at the site boundary, stating that a requirement of gross metering (net generation metering) was unfair and unnecessary. Relevant excerpts from the Order are provided below,~~

> ~~*In terms of metering, including telemetry when required by the CAISO's Tariff, the judge ruled that it is unjust and unreasonable to require QFs that enter into a PGA to gross meter and telemeter generation and behind-the-meter load [i.e., require net generation metering]… The judge found that, to obtain real-time information for reliability of the system, CAISO must measure the actual power flow that appears at the interconnection point between the QF and [IOU]. …[B]asic physics dictates that the flow of energy must change at the point of interconnection. Thus, … CAISO only needs to measure the direct impact on its system; changes in load and generation behind-the-meter [at the site boundary] will be captured at this point."*~~

~~*See* 104 FERC ¶ 61,196, paragraph 19. The CPUC in a standby decision in R.99-10-025, also found the CAISO gross metering, *i.e.*, net generation metering, policy unsupportable, stating in Conclusion of Law 23, *"We should not support the CAISO's gross load metering policy."* *See* D.01-07-027, at 83.~~

~~(a)~~a. CPUC Concludes that Net Generation Metering Is Not Necessary For ~~DL~~ Billing DL Customers NonBypassable Charges.

The CPUC and utility tariffs have historically provided for the use of estimation of customers' consumption as the basis for billing Departing Load (DL) nonbypassable charges, including Tail Competition Transition Charges (CTC), Nuclear Decommission charges (ND) and Public Purpose Program Charges (PPP), instead of net generation metering. Recently the CPUC confirmed that the DL Cost Responsibility Surcharge (CRS) could also be billed based on estimates of customer consumption rather than net generation ~~output~~ metering, in ~~.~~ Energy Division Resolution E-3831. ~~therefore unequivocally answered the question of whether Net Generation Metering was required for calculation of the DL CRS. The answer is no.~~ The Resolution finds:

> *Utility tariff provisions for measuring **and estimating load** for use in billing the CTC **are reasonable for billing the CRS**, as proposed by SCE and SDG&E.*

ED Resolution E-3831, at 26, Finding 6 (emphasis added). The Resolution then orders:

> *Utility tariff provisions for measuring and* ***estimating departed load for use in billing Tail CTC shall be used for billing the CG CRS.***

Id., ~~-~~at 28, Ordering Parag~~r~~raph 3 (emphasis added). The CPUC unanimously adopted this Resolution on July 8, 2004.

~~The FERC and CPUC have thus determined that net generation metering is not necessary in all circumstances. Indeed, it is expressly prohibited by FERC, and the CPUC has ruled that utility tariffs provide reasonable alternatives to net generation metering.~~

~~(b)~~b. Utility Tariff Provisions Provide Customer Options For Alternatives To Net Generation Metering.

SCE Preliminary Statement W and Schedule DL-NBC state that utility will estimate the customer's consumption where metered data is not available.

> *If reliable metered consumption information is not made available to SCE, SCE will estimate the consumption based on that customer's historical load pursuant to Part W, Section 4.b.(3) at the time the customer discontinues or reduces its purchases from SCE. This estimated consumption will also be used as the basis for calculation of a Reference Period Annual Bill.*

SCE Preliminary Statement W.3.a., Sheet 3. PG&E's Preliminary Statement BB similarly provides:

> *If reliable metered consumption information is not made available to PG&E, PG&E will estimate the consumption based on that customer's historical load as set forth in Section BB.5.e.*

PG&E Preliminary Statement BB,2.b, at 2. SDG&E's tariff likewise permits estimation of consumption in lieu of metered data:

> *If reliable metered consumption information is not made available to the Utility, the Utility will estimate the consumption based on that customer's historical load pursuant to this Rule at the time the customer discontinues or reduces its purchases from the Utility.*

SDG&E Electric Rule 23, Sheet 2. The tariffs then uniformly state that customer may choose one of two (or three, in SDG&E's territory) proposed methods for estimation of the customer's consumption.

> *The* ***customer*** *shall specify in its notice the following:*

... Method by which the Departing Load consumption will be determined consistent with the procedures outlined in Part W, Section 4.b.(3).

SCE Preliminary Statement W.4.a.(1), Sheet 4 (emphasis added); *see also* PG&E Preliminary Statement BB.5.c (*"the customer's reference billing determinants will be based upon one of the following two options* ***(to be selected by the Departing Load customer)****"*)(emphasis added) ; *see also* SDG&E Rule 23 D.3.c.

Each utility tariff then provides clear direction to the customer regarding the customer's ~~two~~ options for consumption estimation. For example, SCE's tariff states:

...[T]he Departing Load customer's monthly consumption estimation will be based upon the customer's historical load at the time it discontinues or reduces retail service with SCE, ***using one of the following options:***

(a) The customer's demand and energy usage over the 12 month period prior to the customer's submission of notice; or
(b) The customer's average 12 month demand and energy usage, with such average to be as measured over the prior 36 months of usage.

SCE Preliminary Statement W.4.b.(3), Sheet 6 (emphasis added); *see also* PG&E Preliminary Statement BB.5.c; *see also* SDG&E Rule 23 D.3.c.

The utility tariffs cited above give the customer the option of having their ~~Tail CTC~~nonbypassable charges and DL CRS bills calculated on the basis of estimated consumption derived from historical usage figures. Net Generation Metering is not required to bill Departing Load.

The following section details why utilities prefer a requirement for net generation metering for all projects over point-of-common coupling metering.

~~3.~~4. Utility Positions

The utilities interpret the language of Rule 21 to permit them to require net generation metering on generating units in their respective service territories when the utility believes that such metering is necessary for accurate billing or regional monitoring. The utilities state that mandatory installation of net generation metering is supported by the need to precisely assess the electric service provided to a customer to administer applicable tariffs and charges, or in other words, tariff administration.~~charges~~.

a. PG&E

PG&E identified, in working group meetings, four tariff administration-related needs for such metering:

1) assessment of customer responsibility surcharges (i.e. non-bypassable charges)~~non-bypassable charges~~;
2) assessment of standby charges;
3) determination of the applicability of gas cogeneration rates (this includes the calculation of the monthly gas transportation bills and the annual determination of compliance with PU Code Section 218); and
4) determination of the applicability of self-generation incentives.

Attached Appendix A provides additional detail regarding PG&E's position on net generation metering. PG&E also asserts that the use of non-metering alternatives results in gaps in information and data integration issues and, moreover, requires time-intensive, manual input of data. PG&E further points to customer reluctance to provide customer proprietary data as a problem with non-metering alternatives.
~~[JJ to expand]~~

b. SCE

SCE has a similar basis for opposing the non-metering alternatives to net generation metering; SCE cites the difficulty of re-integrating data due to the lack of a common format for information provided by customers. Moreover, SCE states that some customers are averse to having tariffs administered by estimated usage and have complained about the utility estimates used for billing purposes. SCE thus raises the additional issue of an electric utility's obligation to accurately bill their customers SCE further contends that, due to the uncertainties in accuracy and the incompatibility of data formats, installation of a billing-grade meter is required to measure the output of the customer's generator for acquiring data needed for the operation and planning of their electric systems.

SCE's Rule 9A Rendering of Bills states, in part, that bills for metered service will be based on meter registrations and meters will be read as required for the preparation of bills. Thus, each month, with minor exceptions, SCE reads its customers' meters to determine the usage from which to prepare monthly bills. If SCE is not able to read a particular meter, it is allowed to estimate the read and usage for that billing period according to Rule 17A Estimated Usage.

Rule 17A states, in part, that when accurate meter readings are not available, SCE may estimate the customer's usage on the basis of records of historical use. However, this estimation can only take place for one billing period without an actual read being obtained.

PU Code Section 770(d) states, in part, that the Commission shall require any estimation that is incorrect to be corrected by the next billing period except for reasons beyond the utility's control due to weather or in cases of unusual conditions when such corrections will then be based on an actual reading following the period of inaccessibility. This Section of the PU Code is clear that estimation should be used sparingly and not in an ongoing manner and that eventually a meter read needs to be obtained.

Rule 21 also states that SCE can specify the type and installation of a meter to bill standby and non-by-passable charges. Rule 21 does indicate that less intrusive and/or more cost effective options for providing usage can be used but the rule is silent on using estimation for an indefinite period. To do so would be a violation of PU Code Section 770(d). While Tariffs and Rules can be changed by Advice Letter, the PU Code can only be changed by Legislation. Thus, it would be inconsistent with Section 770(d) of the PU Code to allowing continuous estimation of usage for billing purposes.

SCE's tariffs require billing grade metering to bill DL, CRS and other non-by-passable charges unless a more cost effective and less intrusive method of determining usage is available. Several of the DG customers have interpreted this to mean that the usage can always be estimated. Estimation seems like a good solution to the problem that the lack of a meter presents. However, SCE's tariffs referenced above require that SCE renders accurate bills. In order to accomplish this task, metering is necessary. It is only at times when metered data is questioned or not available that SCE would use estimates for purposes of billing

There are problems when estimated reads are used bill after bill. The first area of concern is that DG customers often reject the estimated bills which requires SCE to obtain usage in a different method and rebill the account. This is an expensive, manual process. Another area of concern with estimating bills is that the on-going estimation of bills was never the Commission's intention. As described above, Rule 9 states accounts will be rendered based on meter registrations, Rule 17 says bills can be estimated based on historical usage but Section 770(d) says that if a bill is not estimated correctly, it must be corrected by the next actual read date. When estimating DG, this meter read never occurs because there is no meter to read. The third area of concern is that with on going estimation, the utility has no assurance it is accurately billing the customer for an accurate amount of DL or CRS. The estimated amount is based on the historical usage over a period of time prior to when the Distributed Generation (DG) was installed. If the customer has a significant increase in load served by the DG, SCE has no visibility to this increased usage when billing for the non-bypassable charges. Thus, SCE is not collecting the proper amount of DL or CRS. When appropriate amounts of DL and CRS are not paid by the customer, the responsibility for this shortfall of DL and DRS then falls to other customers.

Regarding PU Code Section 2827.7,~~.—~~,~~T~~SCE~~he utilities~~ interprets this ~~PU Code~~ Section ~~2827.7~~ to mean that NEM projects may in the future require net generation metering. The history of Assembly Bill 58, with an emphasis on Section 4, amendment to Section 2827.7 of the PU Code, added grandfathering language that was conceptualized for the sole purpose of defining which NEM customers, with NEM eligible generating facilities, were to be exempt from what the utilities term as Non-bypassable charges (i.e., Public Goods Charge) on a prospective basis starting on or about September 2003. PG&E Advice Letter 2405-E and Commission Resolution E-3847 provide further details on this issue and where it is headed. In short, the Commission is due to submit a report to the California Legislature by January 1, 2005, examining who pays Non-bypassable charges on the NEM eligible generation serving a customer's on-site load, and more importantly how it will be calculated. Currently these Nonbypassable charges can be netted out, but once the California Legislature takes action on this issue, probably sometime in mid 2005, NEM customers, according to ~~the utilities~~SCE, will likely no longer be exempt from Non-bypassable charges on their generating facility's output serving on-site load, on a going forward basis, with the possible exception of NEM customers who meet the provisions of PU Code 2827.7. ~~Utilities~~ SCE also believes that even these PU Code 2827.7 exempt customers may not be exempt from all components of the utilities Non-bypassable charges. ~~The~~ SCE~~utilities~~ therefore asserts that this pending change in Non-bypassable charges for NEM customers will likely necessitate the need for generation output metering on all new NEM eligible generating facilities in order to accurately calculate Non-bypassable charges.

SCE's justification to require the installation of net generation meters extends beyond tariff administration, and they reserve the right to require them for system monitoring purposes.
~~[PLACEHOLDER: Distribution Planning and Operations purposes]~~

~~V.~~ c. SDG&E

~~SDG&E simply interprets the current Rule 21 language as requiring net generation metering on all customer generation. SDG&E's position is that it should continue to require such metering on all new customer generation. While it appears that SDG&E has not fully complied with the reporting requirement in Section F.3, SDG&E asserts that it only installs net generation metering on customer generation to administer its tariff provisions.~~

SDG&E has experience with a single DG customer that has no Net Generator (Output) Meter. The customer is responsible for providing the required data. Since the beginning of the DG's operation in 2000, through current day, the data supplied to SDG&E: 1) is provided to SDG&E on a computer spreadsheet and is not verifiable by any other source. Therefore, billing based on the customer supplied data is subject to error and subsequent rebilling ; 2) is not in a compatible billing format so SDG&E must manually manipulate and input the data to its billing system; and 3) typically arrives later than requested and often times, SDG&E must track down the DG customer to obtain the data. This arrangement is labor intensive and more costly with respect to SDG&E's billing operation~~.~~

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Because of that experience, SDG&E recognized early on that alternative methods of obtaining meter data would result in difficulties and additional cost to SDG&E's ratepayers. As a result, SDG&E interprets the current Rule 21 language as requiring net generation metering on all customer generation as a less intrusive and more cost effective option to administer its tariffs.

SDG&E's position is that it should continue to require such metering on all new customer generation. SDG&E reviewed and determined the alternative reporting requirements in Section F.3 were inadequate to meet its needs. SDG&E installs metering on customer generation to effectively and accurately administer its tariff provisions as well as to determine its resource needs to provide safe reliable service to its customers. SDG&E therefore interprets the current Rule 21 language as requiring net generation metering on all customer generation.

Regarding the individual relevant factors listed in Section F.3. of Rule 21, the following are SDG&E's positions:

a. Data requirements in proportion to need for information;

Position: SDG&E requires 15-minute interval data to be used for billing applicable tariff charges and for system planning purposes. The data must be compatible with SDG&E's meter reading system for processing the information. The California Public Utilities Commission requires SDG&E to test any billing meter with a demand of 500kW, and above, annually to insure the metering meets the minimum accuracy standards. The metering may include both the meter and the instrument transformers and must be tested as a system. SDG&E needs to test its metering using its personnel.

b. Producer's election to install equipment that adequately addresses SDG&E's operational requirements;

Position: Difficulties and restrictive conditions exist when using customer-owned instrument transformers to acquire data for SDG&E's use for billing, system planning, and reporting purposes. Therefore, SDG&E requires its High Voltage Service and Metering Equipment standards be met in order to meet SDG&E's needs and maintain a safe work environment.

c. Accuracy and type of required Metering consistent with purposes of collecting data;

Please refer to Position a. above.

d. Cost of Metering relative to the need for and accuracy of the data;

Position: Installing metering pursuant to SDG&E metering standards is required to provide the data SDG&E needs to administer its tariffs and plan its system capacity requirements for the life of the customer's generation system. SDG&E metering is the most cost effective option for *its ratepayers because it avoids the additional costs associated with manual data manipulation as mentioned previously.*

e. The Generating Facility's size relative to the cost of the Metering/monitoring;

Position: The cost to install SDG&E required metering is a relatively minor cost compared a project''s size and cost.

f. Other means of obtaining the data (e.g. Generating Facility logs, proxy data etc.);

Position: This type of data is not reliable for long-term billing, system planning, and reporting, nor is it compatible with SDG&E's meter reading and billing systems. The manual effort required to arrange this type of data into a format suitable for billing purposes is substantial and results in shifting costs to other ratepayers.

~~V.~~g. Requirements under any Interconnection Agreement with the Producer

Position: SDG&E is not aware of any provision in any Interconnection Agreement with a customer that relinquishes its right to require metering in accordance with SDG&E's metering standards.

In short, since the summer of 2002, all three California IOU's have been consistently requiring the installation of net generation meters on any new non-net-energy metered Rule 21 DG interconnections within their service territories.

~~5~~4. DG Customer Position

Certain non-utility Working Group members oppose a blanket requirement for net generation metering. This opposition is based on both the additional cost imposed by such metering and the intrusion onto the customer's property resulting from such metering. Most important to some DG and utility customers is the concern that net generation meters may be used to gather customer confidential and commercially sensitive data. These customers state that net generation metering is not necessary in all circumstances and should not, therefore, be automatically required. These parties agree that under certain specific circumstances, for example where ratepayer funded incentive payments are provided, net generation metering is appropriate; however, it is not and should not be required in all situations. They argue that CPUC-approved non-metering alternatives ~~should~~ continue to suffice for tariff administration purposes, particularly where the customer does not choose to claim compensation for benefits put to grid or incentive payments from such programs as the SGIP.

a. Rule 21 Metering Language is Flexible To Meet Specific Billing Tariff Needs Rather Than Impose A Blanket Net Generation Metering Requirement.

The Rule 21 metering section logically defers to specific utility billing needs set forth in the specific billing tariffs for tariff administration needs, not the other way around. That is, the particular metering or data requirements provided in a specific tariff trump the more general metering provisions of Rule 21, which states its metering requirements are "*for determination of standby charges and applicable non-bypassable charges **as defined in [Investor Owned Utility's (IOU)] tariff***". Rule 21, Section F.3. The key tariff administration requirements, as recognized by the very language of Rule 21, are found in the tariff setting forth the billing requirements, not Rule 21.

These parties also note that Rule 21 requires the utilities to first demonstrate a need for net generation metering before mandating the placement of such metering on the customer's side of the site boundary. These parties ~~also~~ further point to the current language that states that utilities should only require net generation metering to administer a tariff "*to the extent that less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available.*"

Some DG customer groups further state that the Point Of Common Coupling metering provision, which is not a sunset provision, provides the requisite metering configuration for retail service tariff administration:

> *For purposes of assessing [IOU] charges for retail service, the Producer's Point of Common Coupling Metering shall be a bi-directional meter so that power deliveries to and from the Producer's site can be separately recorded. Alternately, the Producer may, at its sole option and cost, require [IOU] to install multi-metering equipment to separately record power deliveries to [IOU's] Distribution System and retail purchases from [IOU]. Such Point of Common Coupling Metering shall be designed to prevent reverse registration.*

Rule 21, Section F.4. Notably, the Federal Energy Regulatory Commission (FERC) has ordered the exclusive use of a point-of-common coupling meter for Qualifying Facilities (QFs) in California and explicitly forbidden the use of net generation meters by the California Independent System Operator (CAISO).

b. The FERC Finds Net Generation Metering Unjust and Unreasonable.

This Commission's decision on whether a blanket requirement for net generation metering should be informed by federal law applied in California. The FERC has addressed the question of whether QFs in California must submit to a CAISO proposed requirement of net generation metering. FERC ordered the CAISO to meter QFs only at the site boundary, stating that a requirement of gross metering (net generation metering) was unfair and unnecessary. Importantly, this decision is binding for QFs in California operating under a CAISO Tariff. Relevant excerpts from the Order are provided below,

> *In terms of metering, including telemetry when required by the CAISO's Tariff, the judge ruled that it is unjust and unreasonable to require QFs that enter into a PGA to gross meter and telemeter generation and behind-the-meter load [i.e., require net generation metering]... The judge found that, to obtain real-time information for reliability of the system, CAISO must measure the actual power flow that appears at the interconnection point between the QF and [IOU]. ...[B]asic physics dictates that the flow of energy must change at the point of interconnection. Thus, ... CAISO only needs to measure the direct impact on its system; changes in load and generation behind-the-meter will be captured at this point [i.e., at the site boundary]."*

104 FERC ¶ 61,196, paragraph 19 (2003); *see also* 108 FERC ¶ 61,273, paragraph 12 (*"Thus, the Commission agrees that the CAISO does not need information on individual generating units behind-the-meter, in order to maintain reliability...."*), paragraph 16 (*"The Judge however ruled that it is unjust and unreasonable to require QFs to gross meter and telemeter generation and behind-the-meter load. The Commission affirmed the Judge's decision, and will therefore direct the CAISO to ... clarify that the purpose of the meters and telemetry is to record only the net impact of QFs."*)(2004).

c. CPUC Determines It Should Not Support CAISO Net Generation Metering.

The CPUC in a standby decision in R.99-10-025, also found the CAISO gross metering, *i.e.*, net generation metering, policy unsupportable, stating in Conclusion of Law 23, *"We should not support the CAISO's gross load metering policy."* D.01-07-027, at 83. Although different terms are used, *e.g.*, gross meter for net generation meter, the CAISO gross metering proposal was equivalent to the Net Generation Metering defined in Rule 21.

The CPUC and the FERC have thus determined that net generation metering is not necessary in all circumstances. Indeed, it is expressly prohibited by FERC, and the CPUC, as noted above, has ruled that it does not support net generation metering.

Moreover, as discussed above, the CPUC recently confirmed that existing utility tariff provisions for estimation of customer consumption are, to use the CPUC's own term, "reasonable." ED Resolution, FOF 6. The CPUC then ordered, "*Utility tariff provisions for measuring and **estimating** departed load for use in billing Tail CTC **shall be used** for billing the CG CRS." Id.*, OP 3 (emphasis added). Thus the current utility tariff provisions for administration of the DL Tail CTC, ND and PPC, that is, estimation of the DL customer's consumption, without using net generation metering data, are to be used for billing.

d. Utility Issues with Data Integration Do Not Justify Requiring A Net Generation Meter Where Tariffs And The CPUC Permit Estimation.

In response to utility complaints of data integration issues and billing complexity, non-utility parties maintain that these issues do not justify the cost of or the intrusion into non-utility property caused by net generation metering. Moreover, where a customer has not opted for the gas cogeneration rate or participated in the SGIP and chooses, as is the customer's right under utility tariffs, to have its bills based on estimated usage, net generation metering is not necessary and should not be required. For example, as cited above, all three utilities' tariffs provide for the use of estimated consumption to bill Tail CTC. Further, the CPUC has determined that this method is reasonable and ordered utilities to use it for billing the DL CRS. Finally, claims that PU Code § 770(d) and electric utility rules preclude the use of estimated consumption for billing purposes misread the statute and rules.

~~e~~a. PU Code § 770(d), SCE Rule 9 and 17 Do Not Restrict The Use of Estimated Customer Consumption For Utility Billing; They Simply Limit The Use of Meter Read Estimates Where A Meter Exists.

SCE ~~mistakenly~~ asserts above that PU Code § 770(d) and SCE Rules 9 and 17 mean that it cannot regularly use estimates of customers' consumption for billing purposes and net generation output metering should always be required. A careful reading of the code and rules demonstrates that ~~SCE is wrong~~this is not true. In fact, the PU Code and utility rules cited do not even address the question of should net generation output metering be required in all circumstances or if the customer's consumption may be estimated. Rather, these authorities provide direction for the utility when the existing utility meter is unable to be read, as may occur due to weather or vandalism, and the meter reading must therefore be estimated for that billing cycle.

PU Code § 770(d) states in relevant part:

> *The commission shall require a public utility that **estimates meter readings** to so indicate on its billings, and shall require any estimate [of the meter reading] that is incorrect to be corrected the next billing period, except for reasons beyond its control due to weather, or in cases of unusual conditions, corrections for any overestimate or underestimate shall be reflected on the first regularly scheduled bill and based on an actual reading [of the meter] following the period of [the meter's] inaccessibility.*

West's Ann.Cal.Pub.Util.Code § 770(d) (2004)(emphasis added). This code section clearly refers to estimation of *meter readings*, not estimation of *customer consumption*. The term "*meter readings*" distinguishes the estimates discussed here, that is, estimates of what the meter would read were it accessible, from the estimates of "*customer consumption*" permitted by the CPUC and the utility tariffs.

SCE Rule 9 is a general rule that applies to metered service, *i.e.*, service provided where a meter records the customer's consumption to which the rates of the relevant tariff apply. For example, service provided under SCE Schedule D-Domestic Service for residential customers is metered service. Service provided to an industrial customer under SCE TOU-8 is also considered metered service. If either the residential customer or the industrial customer decides to install customer generation, such a customer then departs the traditional metered service and become Departing Load. And, while they may still be responsible for certain nonbypassable charges, Schedule D-Domestic Service or TOU-8 and Rule 9 would no longer apply.

Importantly, as noted above, the CPUC has determined that such DL customers are responsible for certain nonbypassable charges and has also provided specific direction for utility billing of these charges. *See* Resolution E-3831, OP 3. Therefore, DL customers believe that the CPUC has unequivocally answered the question of whether Net Generation Metering was required for calculation of the DL CRS, and that the answer is no. Moreover, SCE has specific tariff provisions for the billing of such charges. *See* SCE Preliminary Statement W.3.a., Sheet 3. ~~Notably~~And, both ~~G~~PG&E and SDG&E have similar tariffs. *See* PG&E Preliminary Statement BB; *see* also SDG&E Rule 23. These adopted tariffs permit the utilities to estimate customer consumption for billing of the nonbypassable charges rather than use metered data. The customers, under these tariffs, may then opt to have their consumption estimated for billing purposes for nonbypassable charges rather than metered data. Rule 9 does not apply to the use of estimated consumption for these customers for billing purposes.

Similarly, Rule 17 applies only to traditional metered service where access to the meter is prevented or the meter is determined to be inaccurate. It simply does not apply the use of estimated Departing Load customer consumption for utility billing. PU Code § 770(d) and SCE Rules 9 and 17 are not on point and do not speak to the net generation metering issue.

Some DG customers further state that the planning and operation of the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems; or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the Point of Common Coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, planning and operation concerns do not justify net generation metering. Moreover, as noted by FERC in its Opinion No. 464, the WSCC witness stated, *"[S]ince the implementation of PURPA, QF facilities have typically used [point of common coupling] metering"* and he acknowledged that there had been no major system disturbances. 104 FERC ¶ 61,196, paragraph 39. ~~[This section needs input from Distribution Planners]~~

B. If Net Generation Metering Is Required, What Grade of Meters Should Be Required?

The second metering question to be determined is, if a net generation meter is required, what type or grade of meter it should be. Most customer generation facilities are supplied with a meter or other instrument to measure the amount of power produced by the generating facility. Such measurement devices may or may not be of utility grade accuracy but typically satisfy the customer needs. The data provided by such metering is produced in various formats.

1. ~~1.~~ Current Rule 21 Metering Equipment Provision

Rule 21 simply defines Metering Equipment as:

> *All equipment, hardware, software including meter cabinets, conduit, etc., that are necessary for Metering.*

Rule 21, Section H.

2. ~~2.~~ Utility Position

Utilities assert that the use of a revenue-quality meter [2% (meter must register within 1% accuracy before installation and 2% at all times thereafter) MDMA] is required for assessment of revenue-related costs, including customer responsibility surcharges such as ~~include~~ public purpose program charges and nuclear decommissioning and other non-bypassable charges. SCE in particular cites the need to assess these specific charges as a basis for requiring revenue quality meters.

The utilities further contend that, due to the uncertainties in accuracy and the incompatibility of data formats, installation of a billing-grade meter is required to measure the output of the customer's generator for acquiring data needed for the operation and planning of their electric systems.

Rule 22's Direct Access provisions for electric meter service providers (Meter Data Management Agent (MDMA) and the Direct Access Standards for Metering and Meter Data (DASMMD) could provide a model for establishing metering standards for 3rd Party meters. Vendors could incorporate these standards as part of the DG configurations they supply to DG developers/customers. These meters would be of a Commission/utility acceptable revenue-quality, utility-grade. This would alleviate the need to install a redundant utility meter adjacent to the vendor's meter.

3. ~~3.~~ DG Manufacturer, Project Developer, And DG Customer Position

Some non-utility Working Group members respond to the utility position that the planning, operation and billing accuracy needs mandate a billing-grade meter by again noting that the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems; or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the Point of Common Coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, these parties state that planning and operation concerns do not justify net generation metering in the first place.

Moreover, the imposition of a requirement for billing-grade meters, if DG developers and DG customers are financially responsible for installation, maintenance and operation of the meters, would add redundant costs as the DG systems already come with meters or measuring devices. DG manufactures and project developers believe that this requirement would increase the costs of DG systems and possibly inhibit DG development.

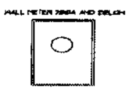
Pricing impacts and space constraints are implicated in treatment of metering issues, particularly for 208V and 480V net generation output meter installations. Notably, higher voltage utility metering sections can be much larger and more expensive than the items described below. For example, installation of revenue grade metering equipment at 13.8 kV imposes an additional cost of approximately $30,000.00

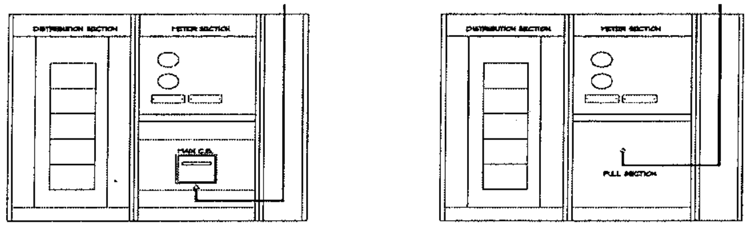
Description of issue:
~~Review~~ The section below reviews the space constraints and costs of utility meter section installations for DG installations. Most DG applications are installed in existing buildings, the cost and floor print of the meter sections is to be reviewed. This is under review if the DG owner has redundant metering abilities installed on-site, and the utility meter appears redundant.

200A in-line meters are small to install, and can be wall hung in a relatively small space. The equipment costs to install the meter panel can be approximately $,1500.00
The costs of the Utility meter and fees can add an additional $2,500.00

400A to 800A meter installations require an additional switchboard section that can add up to 38" of switchboard width. The installed cost of this additional section can be approximately $2,000.00 to $3,000.00, and the Utility meter and fees can be an additional $2,500.00.

1000A to 3000A meters can be up to double the costs of the 400A to 800A meters. The overall floor print of the equipment in only slightly





larger.
200A meter 400-800A meter sections

- ~~Meter cost in dollar terms~~
- ~~Meter cost in percentage terms~~
- ~~PTs and CTs~~
- ~~Spatial constraints~~
- ~~Project timelines~~
- ~~Additional costs: granting utility access, etc (Tom for details)]~~

C. If -Metering Is Required, May Non-Utility or Third-Party Meters Be Utilized And Which Party Is Responsible For The Expense?

Some parties assert their ability to install metering that will meet both the utilities' needs as well as the needs of the customer generator. All parties agree that this and the California Public Utilities companion proceeding are the appropriate forums to develop any needed protocols for third party metering services, perhaps a new proceeding before the CPUC based on Rule 22 metering service provisions. Notably for net energy metering projects, the PU Code clearly establishes cost responsibility for additional meters.

1. ~~1.~~ Current Rule 21 Non-Utility Metering Provision

The ownership, installation, operation, reading and testing of Metering Equipment for Generating Facilities shall be by [IOU] except to the extent that the Commission has determined that all these functions, or any of them, may be performed by others as authorized by the Commission.

Rule 21, Section F.2.

2. Net Energy Metering Projects Are Permitted By The PU Code to Have Additional Metering With The Customer's Consent; This Code Section Also Clearly Delineates Cost Responsibility.

PU Code Section 2827.b.(3) provides the general metering requirement of a single, bi-directional meter for net energy metering projects; such meters are located at the point of common coupling, as it makes no sense to have a bi-directional meter on a generator. Additionally, Resolution E-3847 provides for a net usage basis for billing all nonbypassable charges to net energy metered projects. Therefore, net energy metering projects do not require net generation metering. If, however, the customer consents, and solely for the purpose of determining which and how much a tariff rate or credit applies, an additional meter may be installed at the Electric Service Provider's (here, the utility's) expense. *See* PU Code 2827.b.(3) ("*An additional meter ... may be installed with the consent of the customer generator, at the expense of the electric service provider*").

There are, however, three subsets of NEM projects, those above 50 kW wind, pilot biogas and pilot fuel cell, for which the legislation provides that the customer-generator is responsible for the expense of an additional meter if the existing meter is not bidirectional.

> *Notwithstanding any other provisions of this article, the following provisions apply to an eligible customer-generator utilizing wind energy co-metering with a capacity of more than 50 kilowatts, but not exceeding one megawatt, unless approved by the electric service provider:*
>
> *(a) The eligible customer-generator shall be required to utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions. All meters shall provide "time-of-use" measurements of electricity flow, and the customer shall take service on a time-of-use rate schedule.* ***If the existing meter of the eligible customer-generator is not a time-of-use meter or is not capable of measuring total flow of energy in both directions, the eligible customer-generator is responsible for all expenses involved in purchasing and installing a meter that is both time-of-use and able to measure total electricity flow in both directions.*** *This subdivision shall not restrict the ability of an eligible customer-generator to utilize any economic incentives provided by a government agency or the electric service provider to reduce its costs for purchasing and installing a time-of-use meter.*

PU Code Section 2827.8 (emphasis added); *see also* PU Code Section 2827.9 Experimental Biogas NEM; *see also* PU Code Section 2827.10 Experimental Fuel Cell NEM.

~~V.~~3. ~~2.~~ Utility Position

PG&E recommends that in all cases where the IOU is a combined utility, all gas fired cogeneration DG customers that apply for gas transportation service under the provisions of that utility's electric generation rates, a net electric generation meter is a required. Such metering will be installed and owned by the IOU and the costs of such meter installations will be borne by applicant. If the IOU only provides electric or gas service, i~~I~~f -metering is required, the utilities prefer to own and operate the meters themselves, with the DG customers responsible for the costs of owning, operating and maintaining the meters. The utilities are, however, willing to consider third party provision of metering services if proper controls for DG customer data accuracy and security are implemented, and the utilities are able to integrate the data provided into the various utilities' billing systems. Moreover, the utilities have suggested that the outcome of a CPUC proceeding whereby third-party metering provisions similar to the ones adopted in Rule 22 may be used as a basis for developing similar opportunities for situations where- metering is required.

In the event that the Commission re-opens, per the template as set forth in Rule 22's Direct Access provisions for electric meter service providers (Meter Data Management Agent (MDMA) and the Direct Access Standards for Metering and Meter Data (DASMMD), the issue of 3rd Party meter ownership it makes sense that any meter standards be communicated to vendors such that the meters they install as part of the DG configuration supplied to developers/customers be a revenue-quality, utility-grade, meter. This would alleviate the need to install a redundant meter.

Utilities recognize the additional incremental cost of having to install utility owned and operated meters may affect the economics of new DG installations. However, in the utilities' opinion, the initial costs are insignificant to the on-going administrative costs placed on the utilities and the host customers after customer generation is installed. At this time, there remain significant technical and process hurdles to overcome with any future 3rd Party ownership issues. Most important of these is the difficulty in electronically linking 3rd Party meters with, and the transfer of data to, utility billing systems efficiently. This means accurate and timely data management that minimizes resources, preserves customer confidentiality, and maintains data veracity.

PG&E is not insensitive to the DG perspective on this issue. However, PG&E is very concerned about the significant hurdles which must be overcome prior to the allowance of future 3rd Party meter ownership, paramount of which is the difficulty in electronically linking 3rd Party meters with utility billing systems to receive timely data, minimize resource impacts, preserve customer confidentiality, and to maintain data veracity. As noted above, PG&E uses data from net generation meters for gas and electric billing, proper rate application, and compliance monitoring. It is in the interest of all ratepayers to maintain accurate metering data. Therefore, PG&E recommends these meters not be installed or owned by 3rd parties
~~The utilities' primary concern is that data collection protocols equivalent to those of the utilities must be established.~~

~~V.~~4. ~~3.~~ DG Manufacturer, Project Developer, And DG Customer Position

While some non-utility parties agree that Rule 22-type metering provisions would provide a basis for protocols for third party metering services, they assert that the current Rule 21 language already permits the California Public Utilities Commission to allow third-party provision of metering services for metering.

Some non-utility parties are concerned about the costs of a redundant metering requirement where a third party provider or customer has already installed a billing-grade meter. These parties believe that the installed meter currently meets utilities specifications and allows access to tariff-approved billing data. For these customers, a requirement for a utility-owned meter would impose an additional $4,000 - $10,000 to the installed cost per project, which makes up approximately XX% of a typical DG project.

~~D.[Future Metering Issues]~~

~~For Efficiency Calculations and Benefit-Costs and other data collection needs~~

~~[**PLACEHOLDER:** Metering requirements for other purposes that may be contemplated by the CPUC in the DG OIR and other proceedings, including thermal metering requirements will need to be completed]~~

~~[NOTE: placeholders below]~~

~~V.~~II. Dispute Resolution Process

~~V.~~III. Interconnection Initial and Supplemental Review Fees

~~V.~~IV. Net Metering For Systems with Combined Technologies

When a NEM eligible customer has a photovoltaic generating system in addition to a Wind energy generating system above 50 kW, or even a Biogas and/or Fuel Cell generating system in addition to a photovoltaic generating system, the need for revenue quality metering at the generating facility is imperative in order to calculate credits and charges for the different kinds of generating technologies utilized under this scenario. Whereas a photovoltaic generating system and a wind energy generating system below 50 kW receive credits at the full retail price, all other types of NEM generating systems (i.e., Wind above 50 kW, Biogas and Fuel cell) receive credits based on the generation component of the utility's retail rate only.

~~V.~~V. Interconnection Rules for Network Systems

APPENDIX A
PG&E Net Generation Metering Issue Matrix
Rule 21 – DG OIR

Area	Tariff	Need For Metering	Data Required (Frequency)	Meter Ownership	Notes
Generator gas tariff administration	G-EG/PU Code 218.5, QF Verification	In order to determine compliance with tariff requirement	Total kWh (Monthly)	Have allowed customer owned meters in the past	Calendar-month kWh data is gathered annually in order to calculate calendar-year operating efficiency. Data is used to validate that usage is less than 25,000 therms/year, to meet operating efficiency requirements per PUC Section 218.5
	G-EG/Rule 9	In order to ensure timely monthly gas bills.	Total kWh (Monthly)	Utility	In order to assure timely gas bills, data must be obtained on specified dates (that align with the gas meter read date) within monthly billing cycles and in a format agreeable to the billing system. For new generators that have no PG&E-owned dedicated gas meter.
	G-EG	Ensure accurate gas bills for mixed-usage customers	Total kWh (Monthly)	Utility (preferred)	Where there is mixed gas end-use at a customer's generating facility, net meter data is used to ensure the correct amount of gas is billed under G-EG
Standby Tariff Administration	Schedule S - Reservation Charge and Otherwise Applicable rate Schedule - demand charge	No metered data required, see Notes column	None	N/A	Standby demand charge waiver is provided under conditions of standby agreement (Form 79-280). Reservation Charge & Otherwise Applicable Rate Schedule demand charge
	Schedule S, Special Condition 7	Net generation profile is used to determine when customer is generating at above its load requirement.	Net generation profile metering	Utility	This is an option under Schedule S. Customer opts to be billed for "supplemental" and "back-up" service.

Area	Tariff	Need For Metering	Data Required (Frequency)	Meter Ownership	Notes
	Schedule S	To determine compliance with tariff provision - exemption from CTC charges	Total kWh (Monthly)	Utility (preferred)	Calendar-month kWh data is gathered annually in order to calculate calendar-year operating efficiency.
Non-bypassable charges (CTC, PPP, ND, TTA)	Preliminary Statement, BB	To determine compliance with tariff provision - exemption from CTC charges	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Preliminary Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requirement, metering output is the most accurate means of determining departed load. Other interconnection scenarios (e.g. over-the-fence {OTF}, or where there is no load history) make this method meaningless.
Cost Responsibility Surcharges (CRS)	E-DCG	To determine compliance with tariff provision - exemption from CTC charges, DWR Bond, DWR Power, and Regulatory Asset (RA). The RA will change to a Dedicated Rate Component (DRC) effective 2/1/05	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Prelim. Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requirement, metering output is the most accurate means of determining departed load. Other interconnection scenarios (e.g. OTF, or where there is no load history) make this method meaningless.
Self-Generation Incentive Program (SGIP)		Annual efficiency calculation requires calendar month kWh net gen production.	Total kWh (Monthly)	Utility	Where required per the Self-Generation Incentive Program; and all costs borne by the SGIP
Distribution System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the distribution system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local distribution system operator, for customer generating facilities greater than 1 MW; or generating facilities greater than 250 kW on less than 10 kV systems.

Area	Tariff	Need For Metering	Data Required (Frequency)	Meter Ownership	Notes
Transmission System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the transmission system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local switching center, for customer generating facilities greater than 1 MW.

Dispute Resolution

PG&E supports the use of the existing Rule 21, Section G – Dispute Resolution Process, as a starting point from which to create a revised Rule 21 section on dispute resolution. RealEnergy has suggested changes to the existing language found in Rule 21, and has submitted its proposal for revising the existing Rule 21, Section G. PG&E supports some of RealEnergy's proposals, but not others. PG&E has the following comments on Real Energy's proposals:

- **Real Energy Proposal One.** Each party to a dispute initiated pursuant to Rule 21 must designate one or more participating representatives with authority to make decisions necessary to resolve the dispute within 5 days of the date of written notification that Rule 21, Section G is being invoked. As appropriate, each party must also designate participating technical or support staff within 5 days of the date of written notification that Rule 21, Section G is being invoked. **PG&E Comments.** PG&E agrees with the concept of parties' assigning a designated "decision maker" within a specified time frame from when the formal dispute is initiated. PG&E prefers ten (10) days, as apposed to the five (5) days suggested by RealEnergy. This additional time would ensure availability for an appropriate decision maker. PG&E does not agree that it should be required to designate a technical or support person, let alone do that in 5 days. In many cases, no such technical person will be necessary.

- **Real Energy Proposal Two.** Utility must provide producer with reasonably detailed technical or regulatory justification for interconnection requirements it proposes to impose; it may not rely solely on a general assertion of need to protect safety and reliability under Section B.9. **PG&E Comments.** PG&E opposes this in its entirely. Utilities must be free to justify technical requirements on the grounds that it is needed for safety and reliability when that is true. To do otherwise would gut their discretion to protect the system. Moreover, the purpose of dispute resolution procedures is to set forth substantive mandates for settlement. This is trying to write substantive Rule 21 interpretation guidelines into the dispute resolution and is entirely inappropriate.

- **Real Energy Proposal Three.** If parties are not able to resolve dispute within initial 45-day period, they may continue negotiations. Alternatively, either party may request in writing that the Energy Division provide assistance in resolving the dispute. The other party may also provide Energy Division with its summary of the dispute. Energy Division shall have 45 days from the date of the written request for assistance to meet with the parties in an effort to assist resolution of the dispute. **PG&E Comments.** PG&E supports this proposal. In addition, PG&E proposes to add the language in bold: ".... provide assistance in resolving the dispute**, or, by mutual consent, parties can select a mediator."**

- **Real Energy Proposal Four.** If the dispute may not be resolved with the assistance of Energy Division, either party may file a complaint with the CPUC. **PG&E Comments.** PG&E supports this proposal.

Dispute Resolution

- **Real Energy Proposal Five.** To the extent resolution of a dispute may have application with respect to future projects of the involved producer, the resolution shall apply to such future projects, unless the producer and the utility mutually agree otherwise. **PG&E Comments.** The utilities already have a general duty of non-discrimination under the Public Utilities Code. However, there are already thousands of small generators on line, and there are proposals for many more. It makes no sense to say in the body of Rule 21 that resolution of every dispute with one generator shall apply to all future projects. Moreover, because circumstances can change from project to project, depending on local line loading and design, and the technology involved, what happens to one project may not in fact resolve what happens to another project that may think it is similarly situated, but in fact, is electrically distinguishable. This proposal should not be included in Rule 21.

- **Real Energy Proposal Six.** The results of each dispute resolved pursuant to Rule 21, Section G, revised as proposed by RealEnergy, shall be publicly available. **PG&E Comments.** It is not clear what is meant by this proposal. Absent signing a confidentiality agreement, customers are free to publicly disclose the fact that they have had a dispute with the utility. Unless the customer has publicly disclosed such information, utilities are usually required to keep customer-specific information confidential. In most cases, disputes with utilities are resolved without the need for disclosing such customer information. The Commission should reject this proposal. Furthermore this runs counter to the CPUC's current rules on settlement of disputes (Rule 51) which recognize the important role of confidentiality in settlement discussions – if this is added, it will reduce the number of settlements and lead to more formal complaints.

The Rule 21working group had suggested that the newly developed Massachusetts dispute resolution process also be considered. PG&E is strongly against the use of this process for two reasons. Both parties that have gone though the existing Rule 21 process strongly suggest use of the Rule 21 process after having reviewed the new Massachusetts document. The Massachusetts model has only recently been created and has not been tested for effectiveness. PG&E finds the terms and conditions within that proposal add to the burden rather the making dispute resolution more efficient for all parties.

The option for a DG to approach the Rule 21 working group with an issue was also discussed at the workshop. PG&E's comments are that this option should not be incorporated into the Rule as a requirement, rather let it be known that this could be an option for the DG. PG&E recognizes several problems with requiring this step in the Rule: not all DG have access to the workshop, whether for financial or time considerations, given the workshop locations are moved around the state, and the timing of the workshops, given they are typically held once a month, might not allow timely consideration of a dispute. In addition, some issues are specific to the developer, rather than involving more generic type issues that are usually addressed by the Rule 21 working group.

Rule 21 Dispute Resolution Process

Summary: Rule 21, Section G Dispute Resolution Process

Rule 21, Section G sets forth the following procedures for addressing disputes that arise under Rule 21:

- The California Public Utilities Commission (CPUC or Commission) has initial jurisdiction to interpret or modify Rule 21 or any interconnection agreements entered into under Rule 21 and to resolve disputes regarding a utility's performance under its interconnection tariffs, agreements and requirements.

- Disputes between a producer (*i.e.*, the entity that enters into an interconnection agreement with a utility) and a utility regarding the utility's performance under its interconnection tariffs, agreements and requirements are to be resolved using the following procedures:

    - The aggrieved party is to notify the other party in writing of the known facts relating to the dispute, the specific dispute and relief sought, and express notice by the aggrieved party that it is invoking the Rule 21 dispute resolution procedures.

    - The parties must meet and confer to try and resolve the dispute within 45 calendar days of the date of the dispute letter.

    - If the parties do not resolve their dispute within 45 calendar days, the dispute will, upon demand by either party, be submitted to the Commission for resolution in accordance with the Commission's rules relating to customer complaints.

- Pending resolution of a dispute under Rule 21, Section G, the parties are to proceed diligently with the performance of their respective obligations under Rule 21 and any interconnection agreement.

- Disputes as to the implementation of Rule 21's dispute resolution process are subject to resolution pursuant to Rule 21, Section G.

RealEnergy Dispute Resolution Experience

In early 2003, RealEnergy submitted applications to interconnect three projects with PG&E's "spot" network in San Francisco. During interconnection discussions, PG&E consistently proposed requiring that *15% of the total nameplate rating of PG&E's transformer be imported during a building's minimum load period.* This proposed requirement would have precluded RealEnergy from developing any projects in San Francisco.

The 15% transformer import requirement was not contained in Rule 21 or PG&E's

Interconnection Handbook. In fact, Rule 21 provides, for radial systems, that the minimum power import requirement is 5% of the generating facility's gross nameplate rating.[1] PG&E had previously (in 2001) applied the 5% generating facility standard to a RealEnergy "spot" network project in Oakland. No safety or reliability problems have arisen at the Oakland project.

Despite numerous requests from RealEnergy over a period of approximately eight months, PG&E was unable to supply RealEnergy with a regulatory or technical justification for the 15% transformer input requirement, or explain why it was seeking to impose different standards on similar "spot" network projects. On September 15, 2003, RealEnergy invoked the Rule 21 dispute resolution procedures and sent PG&E the required written notification.

RealEnergy and PG&E met and conferred within 45 days of the date of RealEnergy's letter, however, they did not conclude the dispute resolution process until December 2003. RealEnergy did not file a complaint with the Commission.

Issues

RealEnergy has identified the following issues with the Rule 21 dispute resolution process as a result of its experience with PG&E:

- Time was wasted trying to ensure the appropriate utility staff participated in negotiations.
- There is a tendency by the utility to interpret Rule 21, Section B.9 as imposing an inviolable duty to ensure safety and reliability, even in the face of verifiable data from the producer or a utility's technical staff or consultant demonstrating a particular interconnection poses no threat to safety and reliability. The result is Section B.9 becomes a barrier to entry.
- If neither party chooses to file a complaint, there is no timeframe for concluding informal discussions.
- Because filing a formal complaint is costly and time consuming, the current Rule 21 dispute resolution process effectively limits dispute resolution to informal discussion between the developer and the utility and precludes development of a record for a neutral decisionmaker through an interim process, such as Energy Division review, in cases where it may be useful to do so.

Recommendations for Improvement

In order to ensure the Rule 21 dispute resolution process affords interested parties a meaningful opportunity to resolve issues before resorting to the formal complaint process, RealEnergy suggests the following revisions be incorporated into Rule 21:

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[1] RealEnergy understands PG&E has prepared a white paper proposing standards for interconnecting projects to "spot" networks. It is not clear how PG&E intends to incorporate those standards into Rule 21.

- Each party to a dispute initiated pursuant to Rule 21 must designate one or more participating representatives with authority to make decisions necessary to resolve the dispute within 5 days of the date of written notification that Rule 21, Section G is being invoked. As appropriate, each party must also designate participating technical or support staff within 5 days of the date of written notification that Rule 21, Section G is being invoked.

- Utility must provide producer with reasonably detailed technical or regulatory justification for interconnection requirements it proposes to impose; it may not rely solely on a general assertion of need to protect safety and reliability under Section B.9.

- If parties are not able to resolve dispute within initial 45 day period, they may continue negotiations. Alternatively, either party may request in writing that the Energy Division provide assistance in resolving the dispute. The other party may also provide Energy Division with its summary of the dispute. Energy Division shall have 45 days from the date of the written request for assistance to meet with the parties in an effort to assist resolution of the dispute.

- If the dispute may not be resolved with the assistance of Energy Division, either party may file a complaint with the CPUC.

- To the extent resolution of a dispute may have application with respect to future projects of the involved producer, the resolution shall apply to such future projects, unless the producer and the utility mutually agree otherwise.

- The results of each dispute resolved pursuant to Rule 21, Section G, revised as proposed by RealEnergy, shall be publicly available.